Longleaf CCS Hub

Longleaf CCS, LLC

Post-Injection Site Care and Site Closure Plan

40 CFR 146.93

<u>Facility Information</u>

Facility Name: Longleaf CCS Hub

Facility Contact: Longleaf CCS, LLC
14302 FNB Parkway
Omaha, NE 68154

Well Location: Mobile County, Alabama
LL#1: Latitude: 31.071303° N
Longitude: -88.094703° W
LL#2: Latitude: 31.070774° N
Longitude: -88.074523° W
LL#3: Latitude: 31.0447129° N
Longitude: -88.0736318° W
LL#4: Latitude: 31.0569516° N
Longitude: -88.1047433° W

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List of Acronyms/Abbreviations

2D	Two dimensional
3D	Three dimensional
ac	Acres
AoR	Area of Review
API	American Petroleum Institute
CCS	Carbon Capture and Storage
CO_2	Carbon dioxide
CMG	Computer Modelling Group
DOE	Department of Energy
EPA	Environmental Protection Agency
°F	Degrees Fahrenheit
ft	Feet
ft^3	Cubic feet
ft/yr	Feet per year
GS	Geologic sequestration
in	Inches
lb	Pounds
LL	Longleaf
m	Meter
mi	Mile
mD	Millidarcies
mg/L	Milligrams per liter
MMscf/d	Million standard cubic feet per day
MPa	Megapascals
MSL	Mean sea level
mt	Metric tons
mt/d	Metric tons per day
Mt	Million metric tons
mt/d	Metric tons per day
nD	Nanodarcies
NOI	Notice of intent
PISC	Post-Injection Site Care
psi	Pounds per square inch, gauge
psia	Pounds per square inch, absolute
SEM	Static earth model
UIC	Underground injection control
USDW	Underground source of drinking water

A. Introduction

The ***Post-Injection Site-Care and Site-Closure Plan*** describes the activities that Longleaf CCS, LLC will perform to meet the requirements of 40 CFR 146.93. This plan provides an overview of the computational modeling, sensitivity analysis, post-injection monitoring, site care, and closure plans. The computational modeling overview will describe the method used to determine the areal extent of the CO_2 plume and pressure differential during the post-injection phase. The details of the computational modeling are discussed in the ***Area of Review and Corrective Action Plan*** and the ***Computational Model*** documents. The results of the modeling work determine the necessary monitoring, site care, and timeframe required to complete the post-injection phase. Upon injection completion, Longleaf CCS, LLC will either submit an amended ***Post-Injection Site-Care and Site-Closure Plan*** or demonstrate to the UIC Program Director through monitoring data and modeling results that no amendments to the plan are needed.

This Plan is based on *Federal Requirements Under the Underground Injection Control Program for Carbon Dioxide Geologic Sequestration Wells*[1] and *Draft Underground Injection Control (UIC) Program Class VI Well Project Plan Development Guidance for Owners and Operators* [2]. According to 40 CFR 146.93, protection of USDWs throughout the PISC phase must be demonstrated in order for Longleaf CCS, LLC to request site closure. A rigorous sensitivity analysis has been performed to assess the impact of variations in reservoir properties to evaluate their effects on the AoR, which is determined by the extent of the CO_2 plume and/or the maximum extent of the pressure front created by injection of CO_2. The post-injection monitoring and the site-closure plan are described in **Section D** and **Section E** of this plan, respectively.

Based on the results of the sensitivity analysis, Longleaf CCS, LLC is proposing that the post-injection monitoring phase of the project continue for 20 years after the

[1] EPA (U.S. Environmental Protection Agency). 2010. *Federal Requirements Under the Underground Injection Control (UIC) Program for Carbon Dioxide (CO2) Geologic Sequestration (GS) Wells Final Rule* (40 CFR 146.93). Washington, D.C.
[2] EPA (U.S. Environmental Protection Agency). 2011. *Draft Underground Injection Control (UIC) Program Class VI Well Project Plan Development Guidance for Owners and Operators*. EPA 816-D-10-012, Office of Water (4606M), Washington, D.C.

cessation of injection, at which time Longleaf CCS, LLC plans to submit evidence to the EPA demonstrating that the plume is moving as predicted and no longer poses a risk to USDWs. Longleaf CCS, LLC will then notify EPA Region 4 UIC Branch with a Notice of Intent (NOI) for site closure at least 120 days before initiating site closure procedures. After authorization has been received from the UIC Program Director, Longleaf CCS, LLC will plug all remaining monitoring wells, as described in the ***Injection Well Plugging Plan,*** and restore the site to pre-operational conditions.

B. Post-Injection Period Computational Modeling

Computational modeling of the Longleaf CCS Hub for this plan is reflected in the injection phase modeling efforts conducted for and described in the ***Area of Review and Corrective Action Plan***. Modeling was conducted to represent 30 years of injection and 20 years of post-injection elapsed time as well as longer post-injection times. All baseline and monitoring data will be incorporated into the model to track and update predictions of the plume and pressure front evolution with time.

The model results show CO_2 plume migration in up-dip directions to the northwest, southwest, and southeast, which follows the mapped geologic structure. Because of the continuity of the Paluxy Formation, including the lack of lateral confinement and favorable reservoir properties, the AoR extent is determined by the CO_2 plume. The model results indicate that the pressure buildup during CO_2 injection recedes to pre-injection levels shortly after the end of CO_2 injection. The computational model shows that the CO_2 plume is predictable in its movement following 20 years of post-injection monitoring (50 years after the start of injection).

The following modeling work illustrates the difference between a 20-year and 50-year post-injection monitoring period at the Longleaf CCS Hub. The results indicate that at the end of the proposed post-injection modeling timeframe of 20 years, the plume has migrated 2.3 miles due west from injection well LL#1 compared to 3.0 miles at the end of 50 years.

B.1 Pre- and Post-Injection Pressure Differential

Changes in pressure relative to the initial reservoir conditions were calculated from the simulation model to determine the project AoR. The reservoir pressure prior to injection is considered the initial pressure. Reservoir pressure measurements taken prior to injection will be used to further refine the pressure distribution in the computational model, should it vary from the collected data at the proposed injection site.

Numerical simulations were conducted for 30 years of CO_2 injection through the four proposed injection wells at a rate of 1.25 MT/year per well. The simulations were continued for 20 years as well as for 50 years after the cessation of injection to assess the CO_2 plume and pressure front evolution with time.

The critical pressure value necessary to force fluids out of the injection zone and into the lowermost USDW (calculations provided in the ***Area of Review and Corrective Action Plan***) was calculated to be 166 psi.

Since the CO_2 plume was found to move beyond the elevated pressure front the AoR for the Longleaf CCS Hub is governed by the CO_2 plume extent. During injection, the maximum pressure buildup in the reservoir was observed in the uppermost portion of the Paluxy Formation. Therefore, the pressure buildup images presented through this document are shown for this horizon (computational model layer 12).

At the LL#1 injection well, a maximum pressure differential of 676 psi was observed in the top Paluxy injection interval early in the injection phase (**Figure 1**). This pressure is due to the increased saturation of the non-wetting phase which impacts the relative permeability. Reservoir pressure steadily declines from the maximum differential pressure during the injection phase. Following the end of CO_2 injection, reservoir pressure quickly declines toward initial pressure.

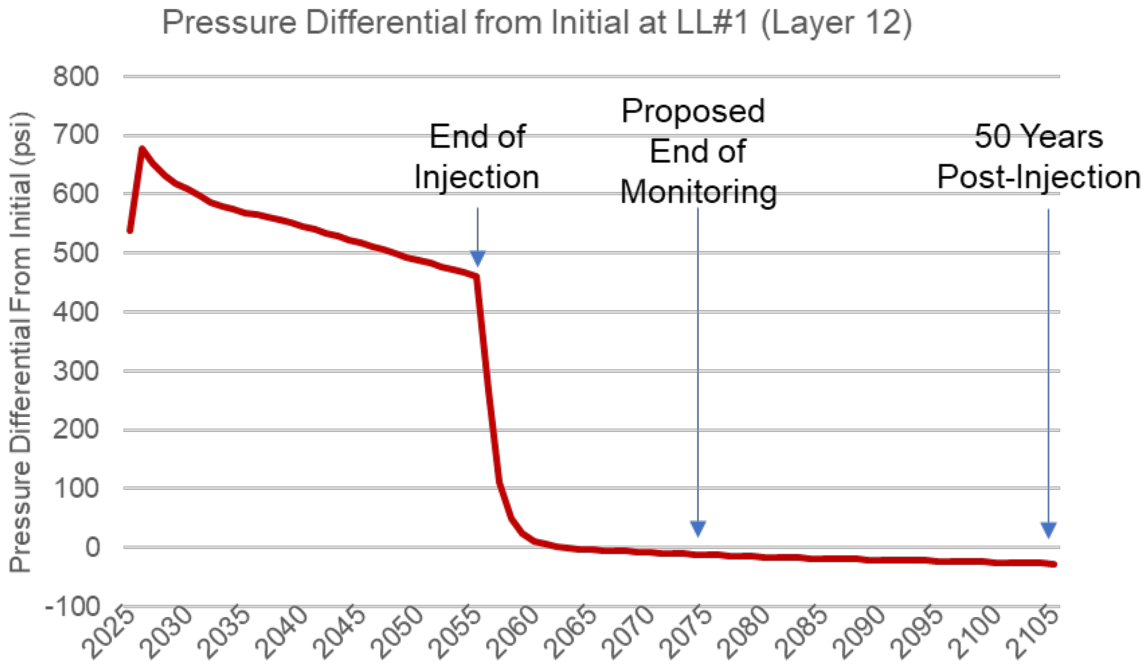

Figure 1: Pressure differential around the LL#1 injection well in the upper Paluxy.

The calculated fracture gradient used for the Paluxy Formation is 0.70 psi/ft. This value will be confirmed during initial well testing operations prior to CO_2 injection, as outlined in the ***Pre-Operational Testing Plan.*** For modeling purposes, a value of 0.63 psi/ft, which is 90% of the maximum calculated fracture gradient, was used to represent the threshold for maximum allowable injection pressure within the Paluxy. This represents a pressure of 6,388 psi. This is outlined in greater detail within the ***Area of Review and Corrective Action Plan***.

The pressure gradient at the Longleaf CCS Hub is 0.463 psi/ft based on gauge data collected from the D-9-8#2 Paluxy in-zone monitoring well at the Citronelle Field storage demonstration.[1] The baseline pore pressure in the Paluxy was recorded in the shallowest upper Paluxy sandstone interval with a top gauge at 9,416 ft and a bottom gauge at 9,441 ft. The baseline pressure at the top gauge was 4,369 psi and at the bottom gauge was 4,385 psi, as shown in **Figure 2**.

[1] Freifeld, B. et al. "The Modular Borehole Monitoring Program: a research program to optimize well-based monitoring for geologic carbon sequestration". Energy Procedia 63 (2014) 3500-3515.

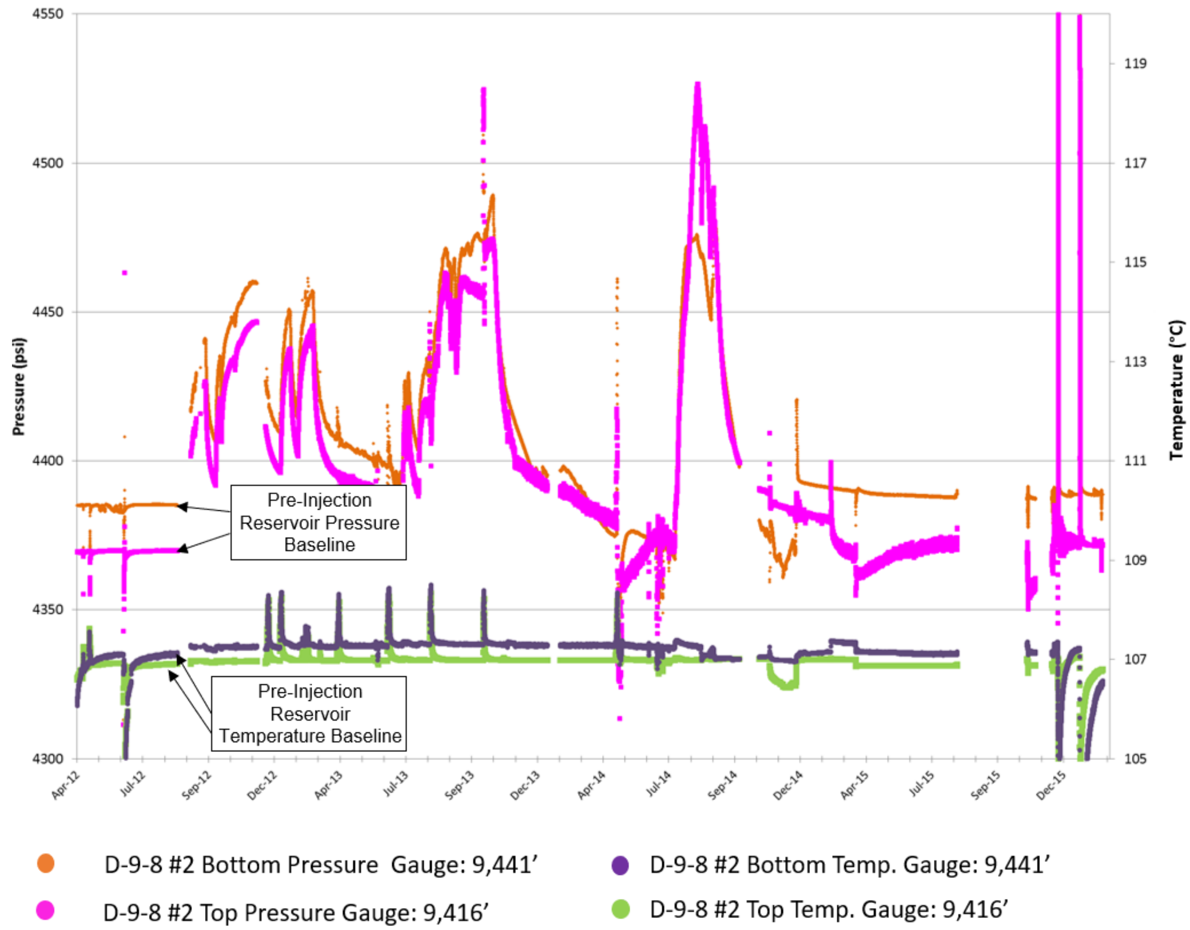

Figure 2: Citronelle D-9-8#2 Well Pressure Gauge Data

A calculated critical differential pressure threshold of 166 psi is used to define the extent of the pressure front for the purpose of determining the AoR. The pressure front is defined as "the minimum pressure within the injection zone necessary to cause fluid flow from the injection zone into the formation matrix of the USDW through a hypothetical conduit that is perforated in both intervals"[1]. The AoR is determined by the maximum extent covered by the CO_2 plume and pressure front. Details of the pressure threshold calculations are provided in the ***Area of Review and Corrective Action Plan***. The simulation model shows that dynamic reservoir pressures across the storage complex drops below the critical pressure value of 166 psi two years following the end of CO_2 injection.

[1] United States Environmental Protection Agency, *Underground Injection Control (UIC) Program Class VI Well Area of Review Evaluation and Corrective Action Guidance*, May 2013

To demonstrate the model behavior, **Figure 3** shows the pressure differential for the 30-year injection period and 20 and 50 years of post-injection monitoring at three monitoring well locations within the upper Paluxy. The wells are located at distances of 4.3 mi to the southeast (IOB#3), 2.4 mi to the southwest (IOB#4), and 4 miles west (IOB#5) of injection well LL#1. Maximum pressure differential values are reached at the end of CO_2 injection before quickly declining towards initial pressure conditions. Observation well IOB#4 has a maximum pressure differential of 286 psi, while both IOB#3 and IOB#5 have maximum pressure differential values below the critical pressure value of 166 psi.

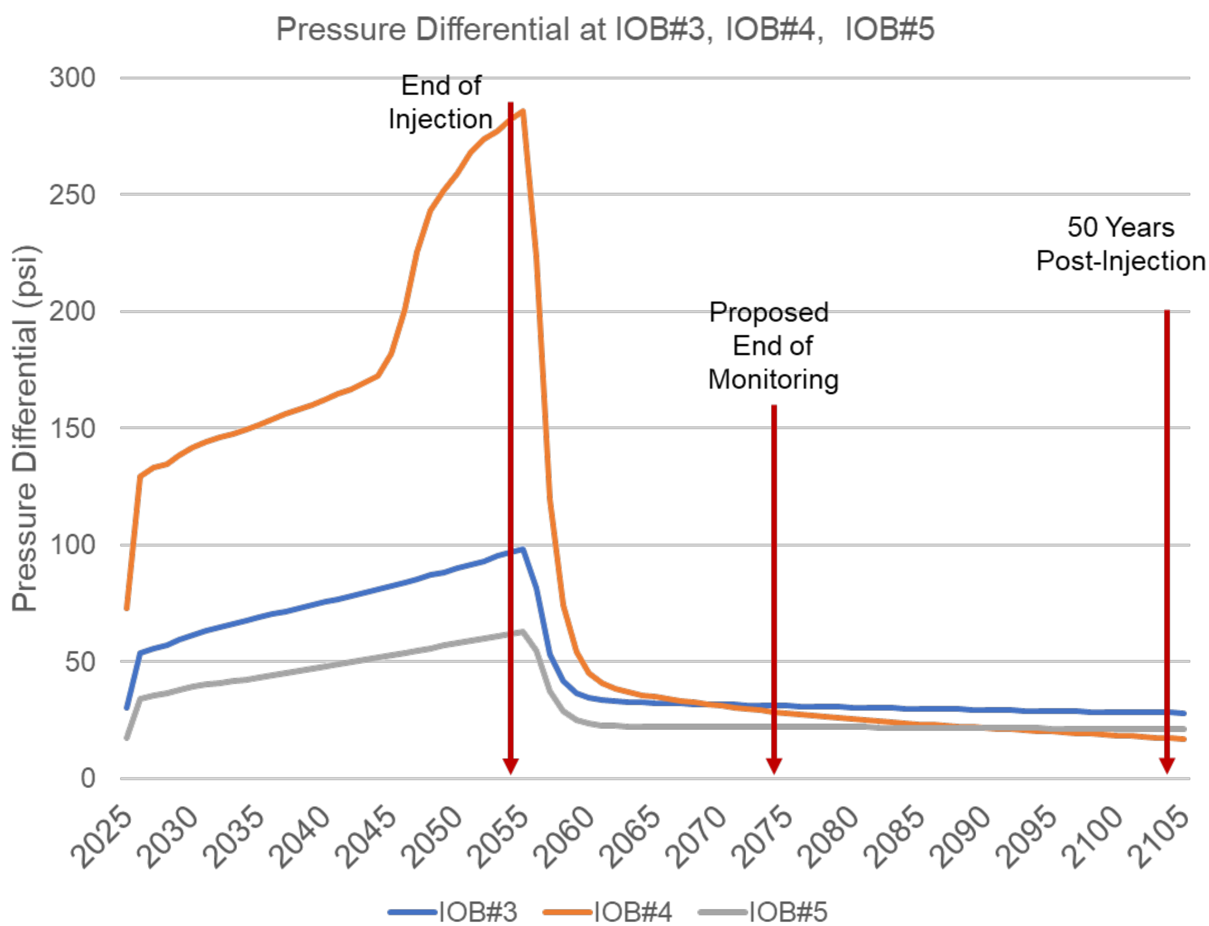

Figure 3: Pressure differential around three Longleaf CCS Hub in-zone observation wells.

The pressure differential over time was mapped for the Upper Paluxy injection area, as shown in both aerial and cross-section view for the Longleaf CCS Hub in **Figure 4** and **Figure 5**. Note the 30x vertical exaggeration to show the layer details in **Figure 5**. As these figures demonstrate, the largest pressure differential values are observed at the injection wells in the upper portions of the storage reservoirs. Once the injection period concludes, the pressure rapidly declines towards initial pressure conditions.

B.2 Predicted 3D Extent of the Free-Phase CO_2 Plume and Associated Elevated Pressure Front at Site Closure

The migration of the CO_2 plume during injection and 20- and 50-years post-injection was modeled for the Longleaf CCS Hub. CO_2 plume migration was analyzed by mapping the plume extent over time, both from an aerial viewpoint of the maximum extent of the plume in computational model layer 12 in **Figure 6** and from a cross-section view of the model at the LL#1 injection well in **Figure 7**. Injection operations may be adjusted to limit the CO_2 extent in the top model layer 12. The outer edge of the CO_2 plume is defined as pore space saturation of 5% CO_2.

The aerial view of the CO_2 plume shows expansion of CO_2 from the injection wells in a uniform fashion for the first 10 years of injection. The CO_2 plumes begin to converge between injection years 10 and 20, and the structure of the storage reservoir begins to define the shape of the CO_2 plume by the end of injection in year 30.

Following the end of CO_2 injection, the CO_2 plume begins to migrate up-dip following the reservoir structure to the northwest, southwest, and southeast. By years 20 and 50 post-injection, the effects of residual trapping are observed, and the CO_2 plume continues to migrate in a predictable manner as free-phase CO_2 travels up-dip along the structural pathways.

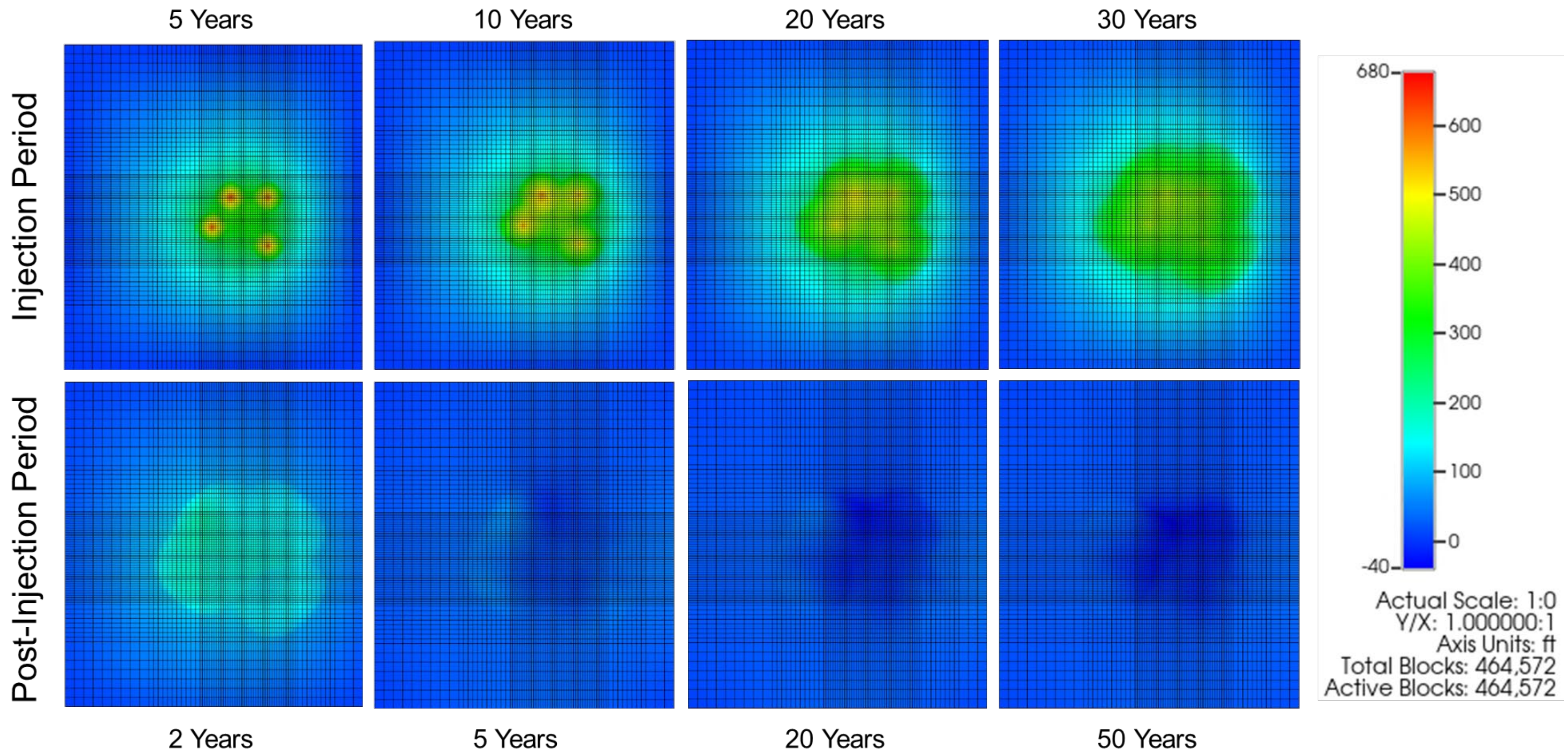

Figure 4: Aerial view of the pressure differential in the Upper Paluxy (computational model layer 12) during CO_2 injection and 50 years post injection

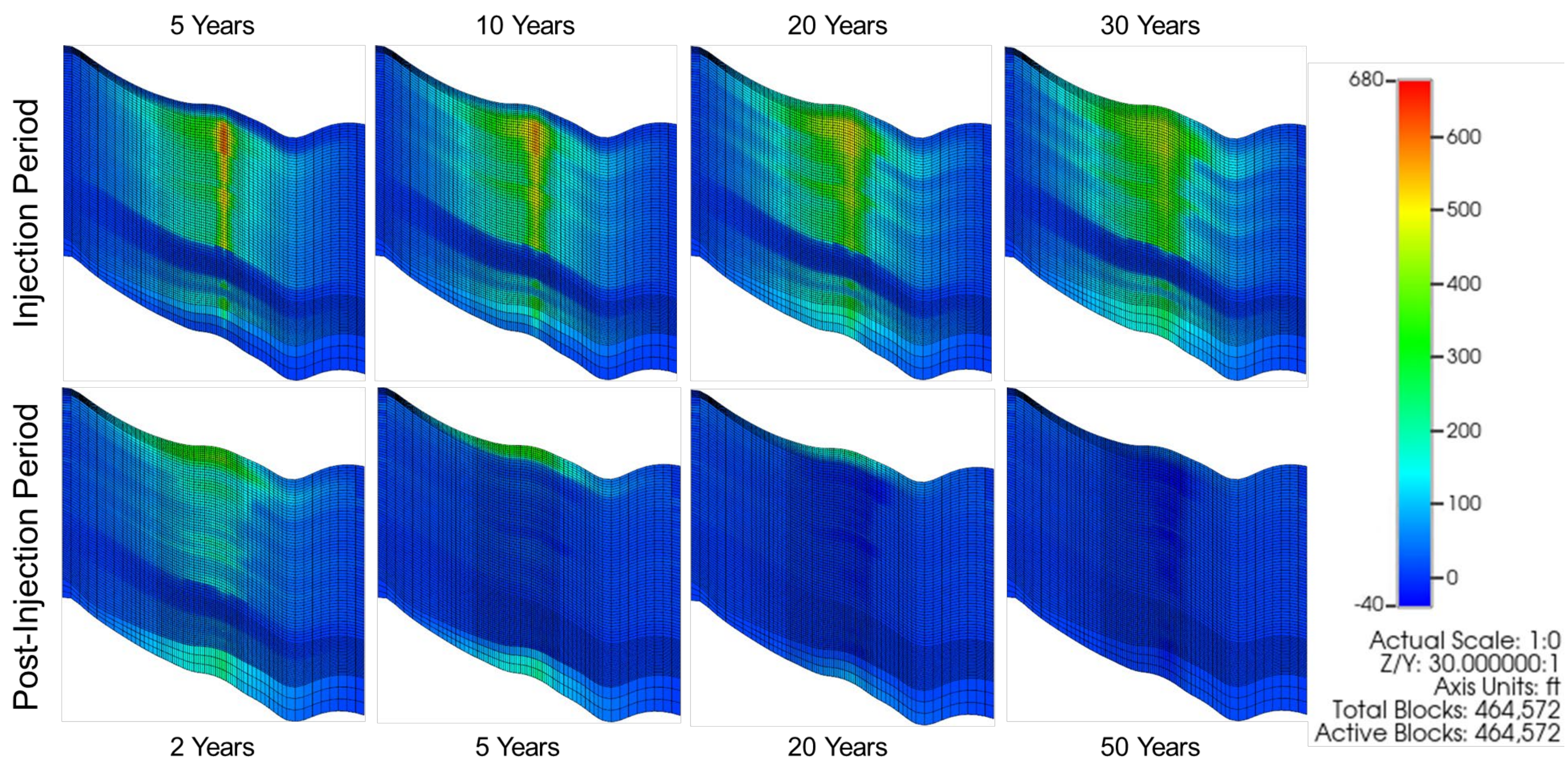

Figure 5: Cross-section view of the pressure differential for the Longleaf CCS Hub at LL#1 during CO_2 injection and 50 years post injection

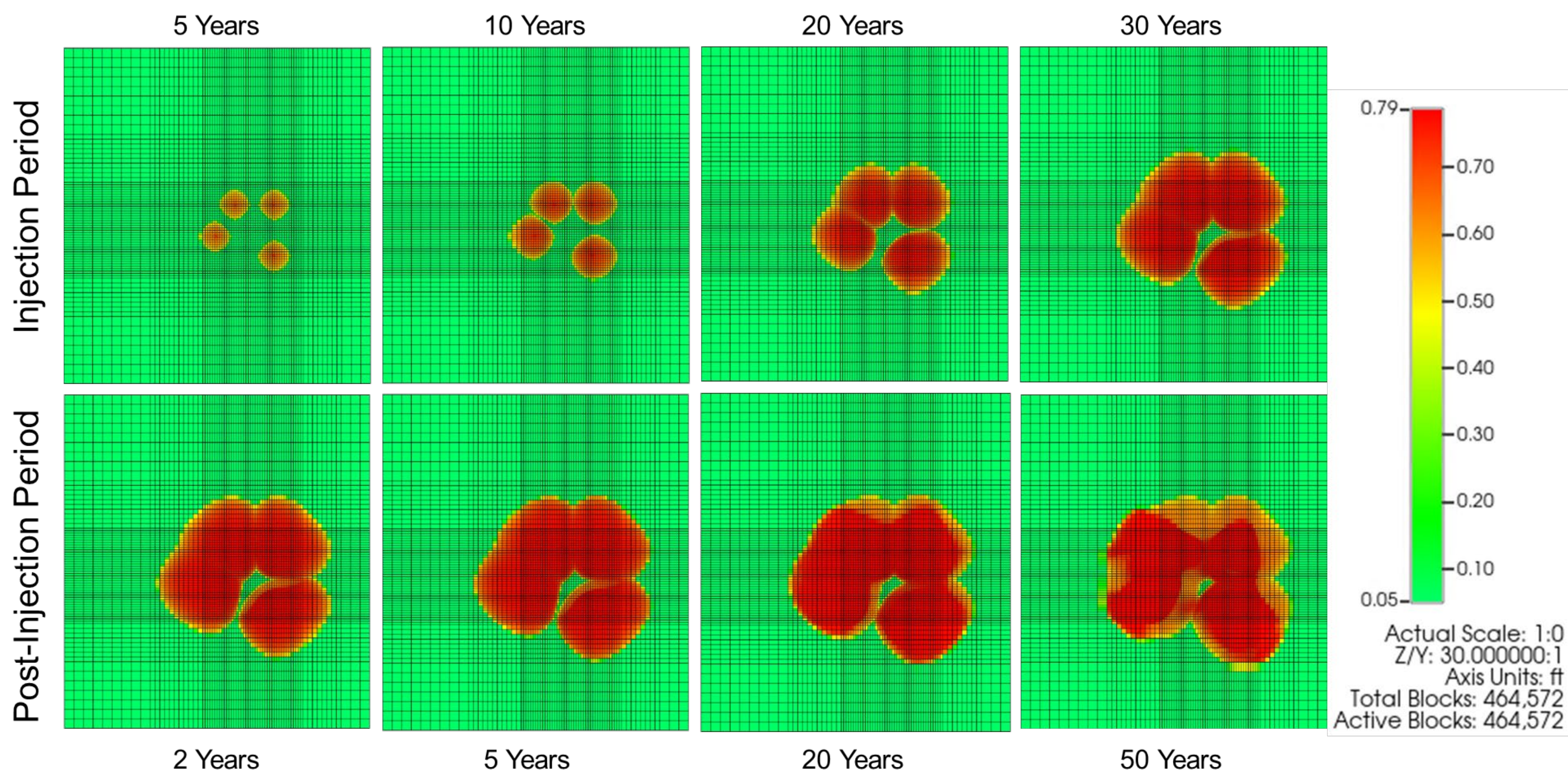

Figure 6: Aerial view of the CO_2 plume extent in the Upper Paluxy (computational model layer 12) during CO_2 injection and 50 years post injection

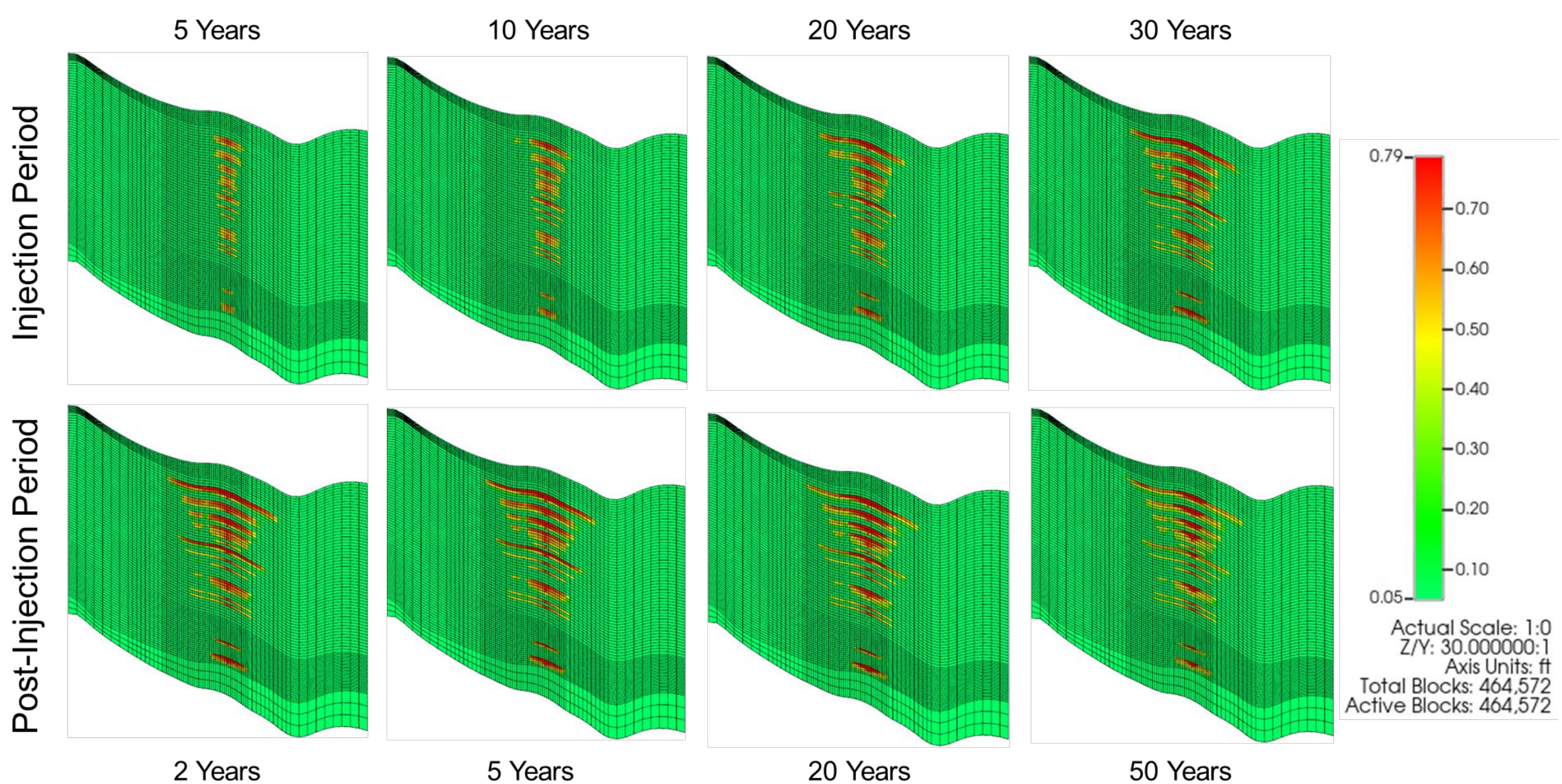

Figure 7: Cross-section view of the CO_2 plume extent for the Longleaf CCS Hub at LL#1 during CO_2 injection and 50 years post injection

The cross-sectional view of the CO_2 plume evolution shows that the CO_2 migrates upward within the injection zone layers and is well contained by interbedded shale layers with low permeability. The highest modeled CO_2 saturation is in the vicinity of the injection well, as indicated by the color palette, with lower concentrations of CO_2 on the periphery of the plume and within the underlying layers of the injection zones in the computational model. Note the 30x vertical exaggeration to show the layer details in the cross-sections. Additional discussion of model runs past 50 years is provided below in Section B.3**.**

B.3 Alternative Timeframe Proposal

Regulations state that monitoring of the CO_2 injection site must be performed for 50 years following the cessation of injection or for an alternative duration at which time the project no longer poses a risk of endangerment to the overlying USDWs (40 CFR 146.93(c)). Longleaf CCS, LLC is proposing an alternative PISC timeframe of 20 years for the Longleaf CCS Hub. This timeframe is supported by the computational model results and model sensitivity analysis that demonstrate the CO_2 plume is in a predictable state and that the operation for long-term, safe, and secure geologic storage of the injected CO_2 poses no threat to the overlying USDWs.

The analysis and modeling supporting the alternative 20-year PISC and site closure timeframe benefitted greatly from the detailed data collected from the Citronelle "Anthropogenic Test" Project located to the west of the AoR. This project was supported by the Southeast Regional Carbon Sequestration Partnerships (SECARB). The project provided extensive characterization of the subsurface to the west of the AoR including detailed core analysis, well logging, injectivity testing, and geochemical sampling from the Paluxy Formation and overlying confining zones. The project also provided rigorous measurements of reservoir pressure, temperature, and other reservoir properties. See more detailed discussion of the Paluxy Formation tests in ***Section B.1*** and the published work on the Citronelle "Anthropogenic Test" Project cited in the ***References*** section of the ***Application Narrative***.

All available site-specific data has been incorporated in the AoR delineation modeling that is outlined in detail in the ***Area of Review and Corrective Action Plan***.

This data includes reservoir properties from the petrophysical logs and core data for the Paluxy reservoir as well as information relative to the occurrence of geologic formations and their associated structural features. Additionally, the model reflects that there are no abandoned wells in the AoR, the base of the deepest USDW is 1,700 feet below ground surface with approximately 8,380 feet between the top of the injection zone and this USDW, and the subsurface at the Longleaf CCS Hub is structurally benign with no significant fault or fold features that would contribute to the presence of natural fractures potentially acting as conduits for fugitive fluid flow out of the targeted injection reservoir, as reported in the ***Application Narrative***. Thus, the CO_2 plume is projected to stay in the injection zone through the modeling timeframes.

Detailed in the following sections is evidence that demonstrates the proposed 20-year alternative PISC timeframe is appropriate for the reservoir conditions present at the Longleaf CCS Hub. Each of the sensitivity analysis cases indicates a predictable CO_2 plume behavior.

The rate of CO_2 plume movement in the up-dip direction to the west of injection well LL#1 is shown in **Figure 8**. The results of the computational model show that the CO_2 plume migration slows significantly following the end of CO_2 injection. From the Year 1 date of 2025, the CO_2 plume moves approximately 10,000 ft until the end of the 30-year injection period, or a rate of about 333 ft/yr. Following the end of injection, the CO_2 plume migration slows to a steady, predictable rate. The plume moves an additional 5,600 ft over 50 years post-injection, or a rate of about 112 ft/yr.

At the end of the 20-year proposed PISC timeframe, the plume is projected to migrate 2.3 miles away from the LL#1 injection well location. At the end of 50 years post-injection, the CO_2 plume is projected to move an additional 0.7 miles outward from LL#1. Thus, the CO_2 plume has reached approximately 83% of the distance it will travel in 50 years at the end of the proposed 20-year PISC timeframe. Further, this analysis has also demonstrated that the evolution of the plume is similar in a variety of cases due to the regional dip and exceptional geologic storage qualities of the storage complex.

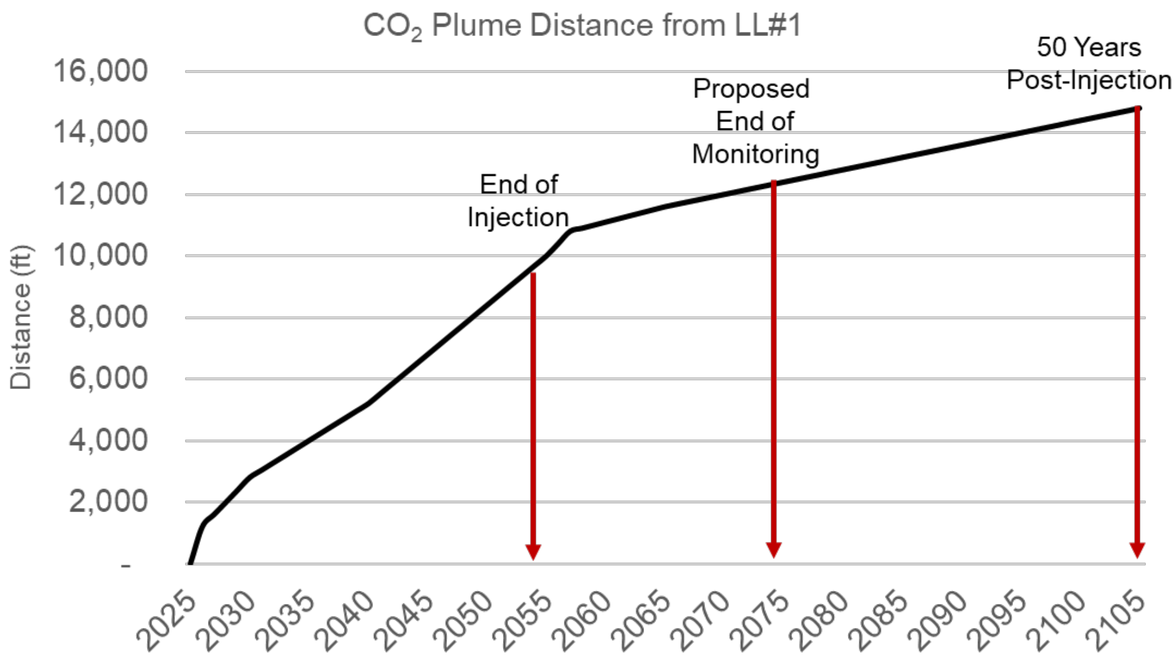

Figure 8: Rate of CO_2 plume migration west from LL#1

The model was run over a period of 180 years (30 years of injection and 150 years of post-injection), with time-zero represented by January 1, 2025, to evaluate the long-term development of the CO_2 plume and identify a timeframe in which the plume effectively ceases further expansion. Due to the reservoir geology at the Longleaf CCS Hub, the CO_2 plume migrates in a predictable manner along updip structural pathways following the end of CO_2 injection.

During the 180 years of modeling time, the plume expands notably during the injection phase, as shown in **Figure 8**. While there is expansion of the plume during the Longleaf CCS Hub's post-injection pressure relaxation period, most of the movement has occurred by 180 years of post-injection time. At this time, the computational model of all four injection wells shows that the CO_2 plume measures approximately 7.7 mi east-to-west and 6.2 mi north-to-south, for a total area of 47.7 mi^2, as shown in **Figure 9**. Prior to site closure the computational model will be reviewed to identify any legacy wells located within the final CO_2 plume extent. These wells will be assessed and remediated, as required, to ensure effective CO_2 plume containment and protection of USDWs.

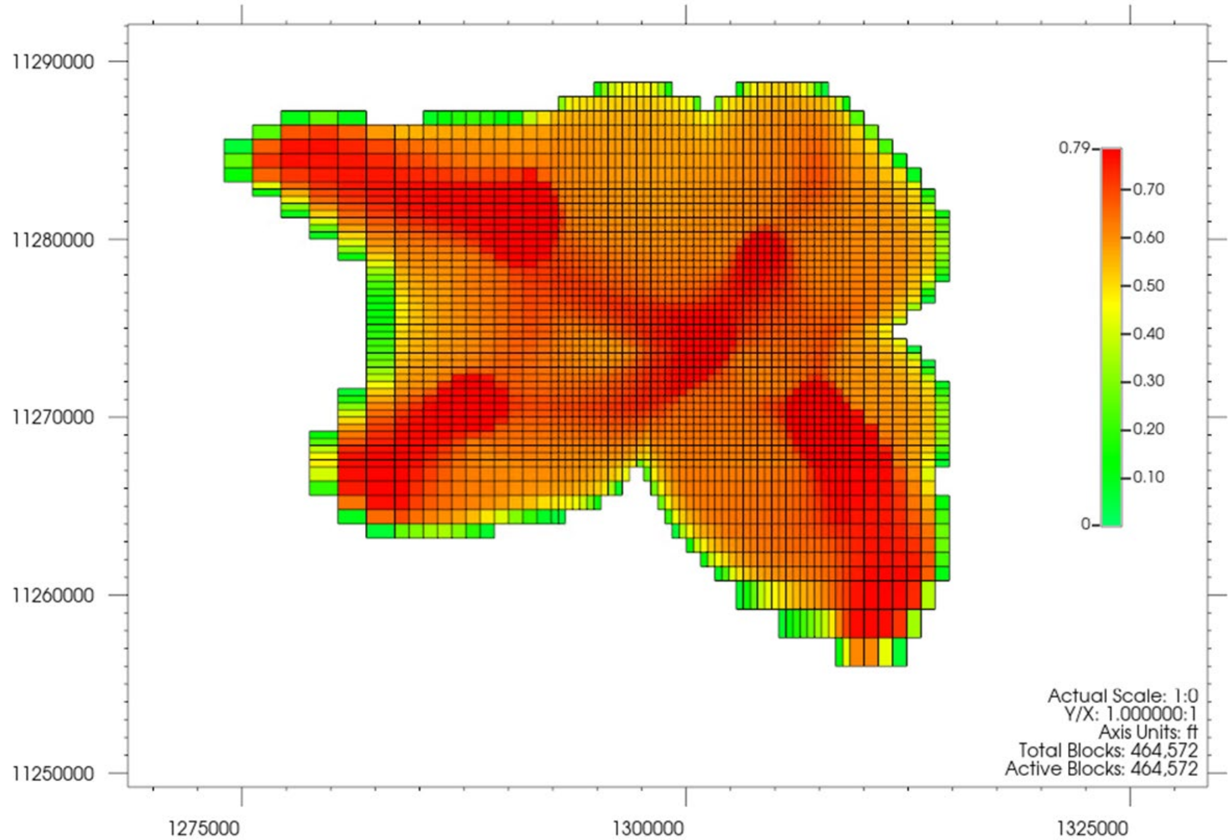

Figure 9: Aerial extent of the CO_2 plume development 180 years post-injection.

B.4 CO_2 Trapping Under Different Mechanisms

The ***Area of Review and Corrective Action Plan*** includes a discussion of the trapping mechanisms included in the computational model for the Longleaf CCS Hub. These mechanisms include structural, residual, and dissolution trapping. **Figure 10** shows the evolution of the injected CO_2 phases over time. A small portion of the CO_2 dissolves in residual reservoir brine, while the majority of the CO_2 remains in a super-critical state. Residual CO_2 trapping increases with residence time in the reservoir as the CO_2 plume migrates within the Longleaf CCS Hub. The remaining super-critical CO_2 will remain structurally trapped within the Longleaf CCS Hub.

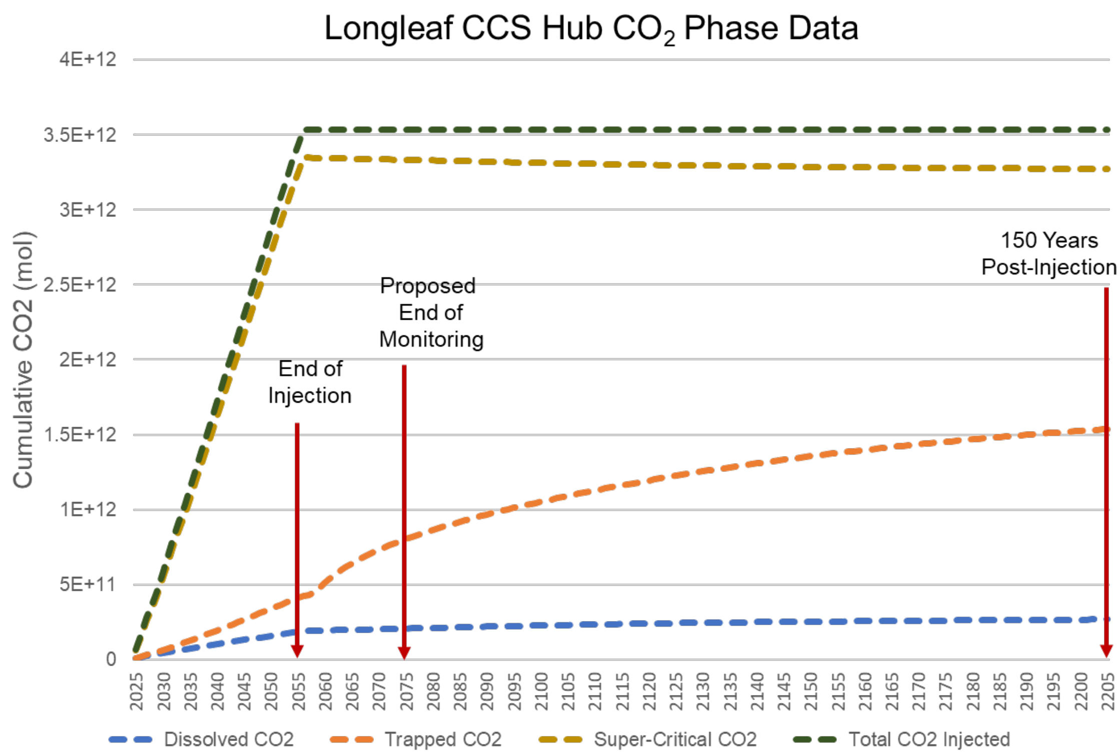

Figure 10: Evolution of injected CO_2 storage phases during and post CO_2 injection at the Longleaf CCS Hub.

C. Sensitivity Analysis

Key reservoir parameters that may impact the extent of the Longleaf CCS Hub AoR, either by the aerial extent of the pressure front or CO_2 plume, were modeled for comparison to the baseline AoR. **Table 1** summarizes the description of each sensitivity parameter and its impact on the AoR boundary.

For two sensitivity cases, including *Case 1. Closed East Model Boundary*, and *Case 4. Decreased Porosity/Permeability*, the AoR was partially or wholly determined by the pressure front at the end of injection, which had a larger aerial extent than the CO_2 plume at the end of the proposed PISC timeframe of 20 years post-injection. For *Case 2. Increased North/South Horizontal Permeability Anisotropy* and *Case 3. Increased Porosity/Permeability,* the AoR was determined by the extent of the CO_2 plume 20 years post-injection. For *Case 5. Increased Seal Permeability*, the sensitivity parameter had no effect on the model results. So, the AoR remained the same as the baseline extent, which was determined by the CO_2 plume area.

The result of each sensitivity case provided an AoR area that was greater than or equal to the baseline AoR area.

Table 1: List of sensitivity cases for Longleaf CCS Hub computational model with resulting CO_2 plume size 20 years post-injection

Sensitivity Case	Base Value	Sensitivity Value(s)	AoR Area (mi^2)
Baseline AoR	-	-	29.1
1. Closed East Model Boundary	Open East Boundary	Closed East Boundary	44.8
2. Increased North/South Horizontal Permeability Anisotropy	y = x	y = 2x	36.4
3. Increased Porosity/Permeability	Φ	Φ + (Φ*0.25)	49.4
4. Decreased Porosity/Permeability	Φ	Φ - (Φ*0.25)	49.0
5. Increased Seal Permeability	k	k*100	29.1

The aerial extent of the AoR sensitivity cases were calculated at 20- and 50-years post-injection, as shown in **Figure 11** and **Figure 12**, respectively. The results of the AoR sensitivity cases at 20- and 50-years post-injection are very similar, and in some cases identical. The AoR for sensitivity Case 4 and Case 5 are identical at 20- and 50-years post-injection. The AoR for Case 1, while similar, does have a small portion of the CO_2 plume extend beyond the pressure front to the west at 50 years post-injection. Likewise, CO_2 plume migration creates a slightly larger AoR 50 years post-injection for Case 2 and Case 3.

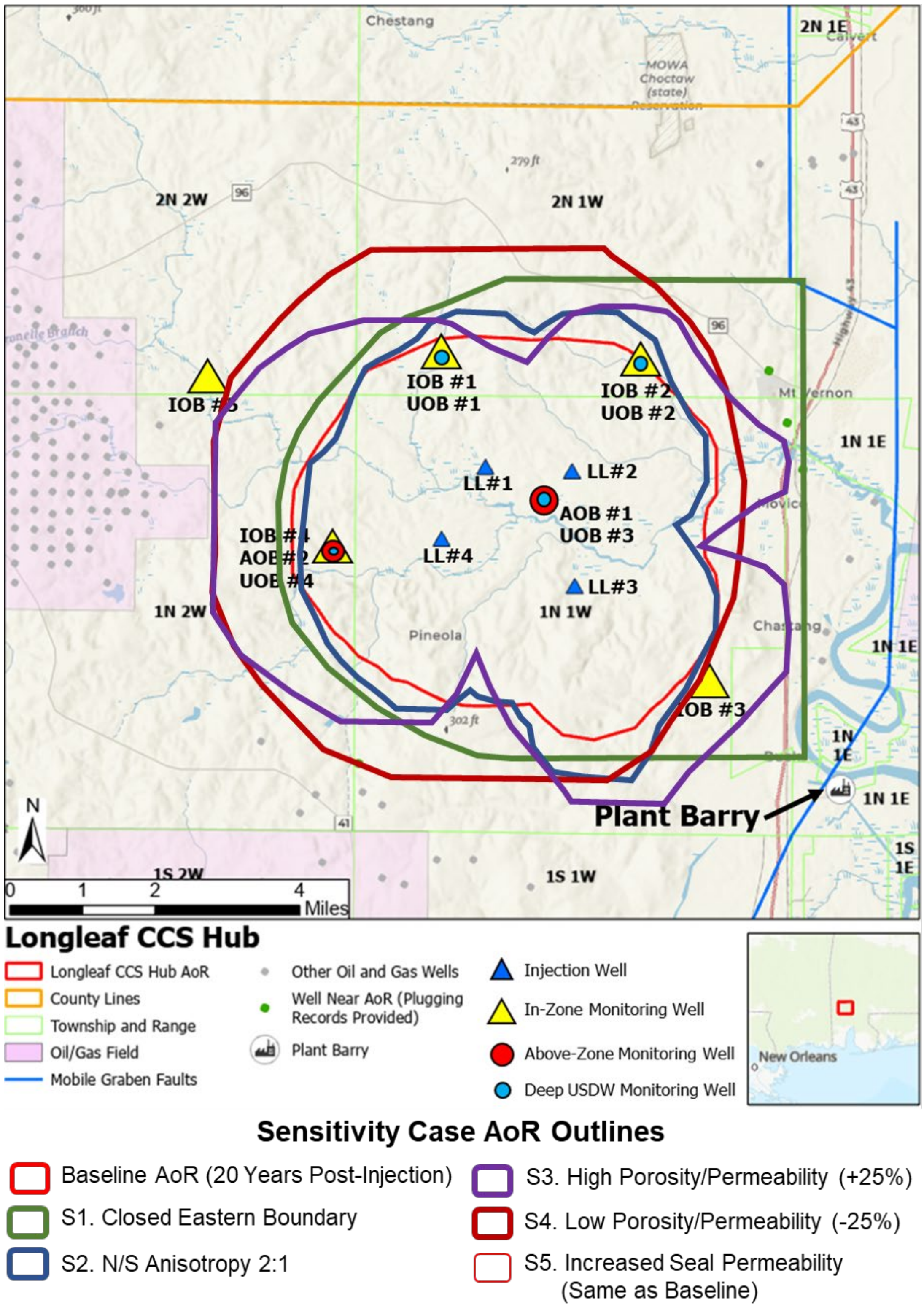

Figure 11: Aerial extent of modeled AoR sensitivity case boundaries 20 years post-injection.

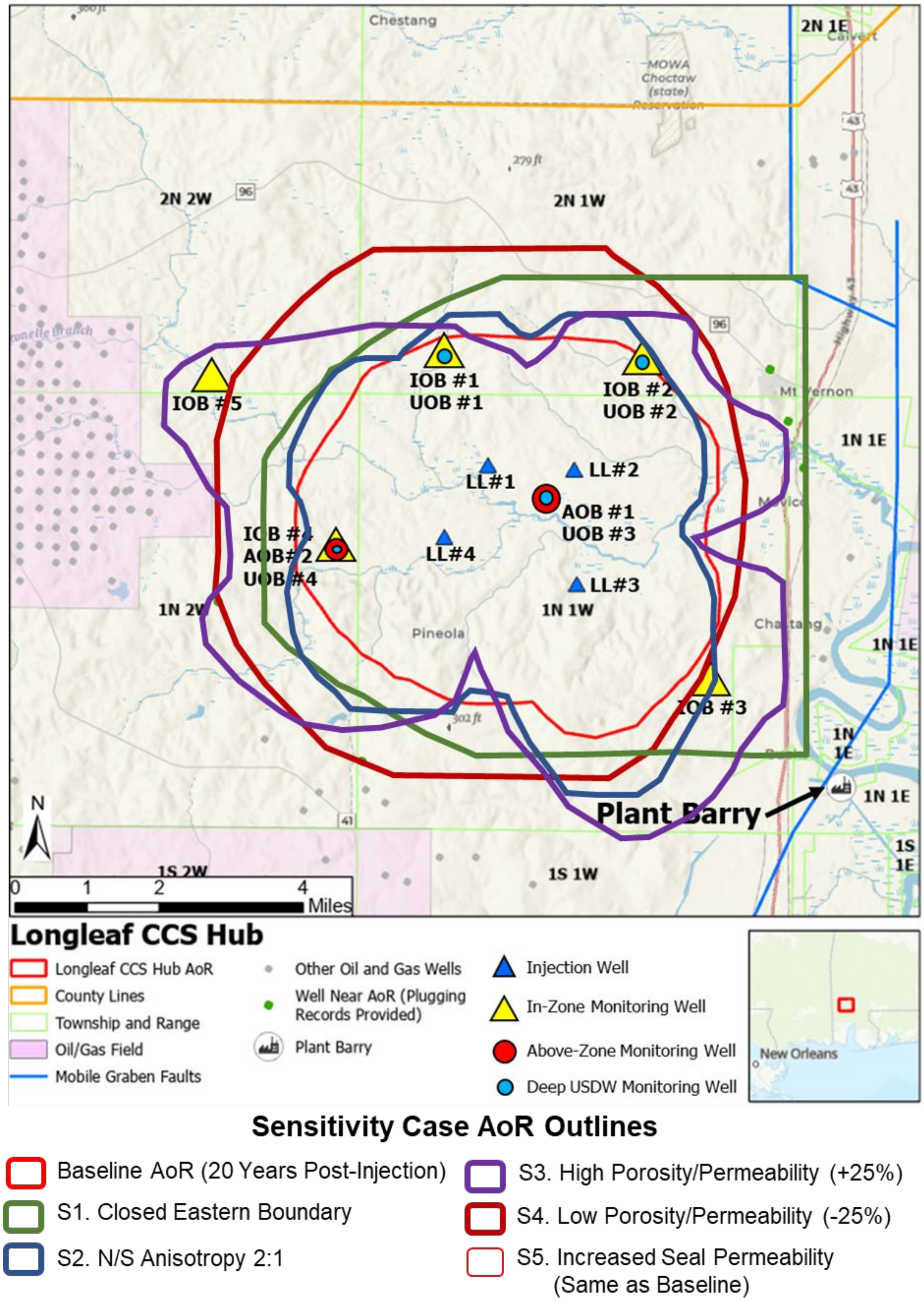

Figure 12: Aerial extent of modeled AoR sensitivity case boundaries 50 years post-injection.

Comparison of the two timeframes shows that the AoR sensitivity boundaries at 20 years post-injection reach between 85% and 100% of the aerial extent of the same sensitivity case boundaries at 50 years post-injection. These modeled outcomes demonstrate confidence in the baseline assessment and firmly indicate that the proposed alternative PISC timeframe of 20 years is sufficient to demonstrate a lack of fugitive CO_2 movement and non-endangerment of USDWs. The following sections discuss the outcomes of each sensitivity assessment.

C.1 Case 1: Effect of Closed Eastern Flow Barrier on the Longleaf CCS Hub AOR

The baseline computational model assumed an open boundary on all sides of the Longleaf CCS Hub with no structural features that would restrict horizontal fluid flow. These parameters assume the Mobile Graben, which is located due east of the Longleaf CCS Hub, allows for unrestricted fluid flow across the Graben barrier, as discussed in the ***Area of Review and Corrective Action Plan.***

The Case 1 sensitivity analysis provided an alternative model parameter by completely closing the eastern boundary of the computational model and restricting horizontal fluid flow, as shown in **Figure 11** and **Figure 12**. This case provided a bookend for the open boundary in the baseline model. Should fluid flow restrictions by the Mobile Graben be observed during CO_2 injection, the sensitivity analysis will provide a benchmark for identifying pressure effects in the reservoir and initiating corrective action that the in-zone monitoring well array will quickly capture.

C.2 Case 2: Effect of Horizontal Permeability Anisotropy on the Longleaf CCS Hub AoR

Interpretation of seismic lines data covering the Longleaf CCS Hub provided insight into the structural geology of the storage reservoir, as outlined in the ***Project Narrative.*** The four injection wells are located at the base of a saddle, with reservoir updip pathways to the northwest, southwest, and southeast.

It was hypothesized that injection of CO_2 into the seat of the saddle formation may concentrate the CO_2 at the low point of the Paluxy formation, creating a “trough” effect.

This could encourage fluid flow across the saddle along the north-to-south reservoir pathway. Increasing the horizontal permeability anisotropy 2-to-1 in that direction tests the in-zone monitoring well array's positioning and ability to discern more rapid arrival of CO_2 should the CO_2 arrive at observation wells to the north and south faster than anticipated by the baseline computational model, as shown in **Figure 11** and **Figure 12**.

C.3 Cases 3 and 4: Effect of Increased and Decreased Sandstone Permeability and Porosity on the Longleaf CCS Hub AoR

Reservoir porosity values in the computational model were determined from core and well log analysis, as described in the ***Area of Review and Corrective Action Plan*** and ***Computational Model*** documents. Porosity values for the Paluxy sandstone layers were variable, ranging from 8.2% to 19.3%. Given this range of values, two sensitivity cases were developed to provide computational model outcomes for porosity values within a 25% degree of higher and lower uncertainty. For Case 3, the 25% higher porosity values ranged from 10.2% to 24.1%. For Case 4, the 25% lower porosity values ranged from 6.1% to 14.5%.

Porosity-permeability transforms were developed to calculate permeability values from porosity values in the computational model reservoir layers, as described in the ***Area of Review and Corrective Action Plan***. Permeability values ranged from 26 mD to 407 mD in the baseline computational model. For Case 3 and Case 4 the permeability values were recalculated based on the 25% increase and decrease in porosity. This provided an increased range of permeability from 44 mD to 1,767 mD for Case 3 and 15 mD to 138 mD for Case 4. As such, Case 3 should provide increased lateral CO_2 movement while Case 4 provides increased pressure buildup in the system due to increasing and decreasing porosity-permeability relationships, respectively, as shown in **Figure 11** and **Figure 12**.

Core analysis performed during characterization well drilling prior to CO_2 injection will provide additional porosity and permeability data that can be used for computational model revision, if required.

C.4 Case 5: Effect of Increased Sealing Formation Permeability on the Longleaf CCS Hub AoR

The permeability of the Wash-Fred Basal Shale at the Longleaf CCS Hub is unknown; however, previous characterization work at Citronelle and well log analysis provided permeability value estimates for the computational model, as described in the ***Area of Review and Corrective Action Plan***. Confining seal integrity and continuity is of utmost importance for ensuring containment of injected CO_2 and protection of USDWs. Sensitivity analysis was developed to test the effectiveness of the Wash-Fred Basal Shale containment given significantly higher permeability values than were used for the baseline computational model.

For sensitivity Case 5, the Wash-Fred Basal Shale permeability was increased by two orders of magnitude (x100) for the eight computational model layers overlying the topmost Paluxy sandstone layer, representing the immediate confining unit above the Paluxy sandstone. The results of the sensitivity analysis showed no change to the AoR compared to the baseline computational model and no penetration of the CO_2 into the Wash-Fred Basal Shale which provides confidence in the reservoir layers performing as effective containment for the injected CO_2 at the Longleaf CCS Hub.

D. Post-Injection Monitoring Plan

Monitoring during the post-injection period will include a combination of groundwater monitoring and storage zone pressure monitoring for the Longleaf CCS Hub. All of the monitoring well locations, methods, and schedules are designed to identify the position of the CO_2 plume and potential pressure front as well as demonstrate that USDWs are not being endangered in accordance with 40 CFR 146.93(b).

Table 2 details the monitoring methods and frequencies that will be employed for the Longleaf CCS Hub to effectively monitor operational parameters and to verify the internal mechanical integrity of the injection well during the post-injection timeframe. The ***Testing and Monitoring Plan*** provides more detailed information on the testing and monitoring technologies that will be employed. The monitoring strategy will utilize a fixed frequency schedule to collect data. A ***Quality Assurance and Surveillance Plan***

(QASP) is also provided as supplementary material included with the ***Testing and Monitoring Plan*****.**

Table 2: Summary of Testing and Monitoring Activities to be Conducted at the Longleaf CCS Hub.

:

Monitoring Activity/Test		Location	Baseline Frequency	Injection Period Frequency	Post-Injection Site Care Frequency
Fiber Optic / Seismic Monitoring	Distributed Acoustic Sensing (DAS)	LL#1-4, IOB#1-5, AOB#1-2	Beginning before injection	Continuous	Continuous
	Distributed Temperature Sensing (DTS)	LL#1-4, IOB#1-5, AOB#1-2	Beginning before injection	Continuous	Continuous
Pulsed Neutron Capture Log (PNC)		LL#1-4, IOB#1-5, AOB#1-2	Once before injection	3yrs after injection begins; Every 5yrs after	At end of injection; Every 5yrs after
Mechanical Integrity Tests		LL#1-4, IOB#1-5	Once before injection	Annually	Annually
		AOB#1-2, UOB#1-4	Once before injection	Every 5yrs	Every 5yrs
Pressure Transient Test		LL#1-4	Once before injection	3yrs after injection begins; Every 5yrs after	At end of injection; Every 5yrs after
Flow Profile Survey		LL#1-4	N/A	Every 5yrs	N/A
Bottomhole Pressure Monitoring		LL#1-4, IOB#1-5, AOB#1-2	Beginning before injection	Continuous surface read-out	Continuous surface read-out
Wellhead Pressure Monitoring	Tubing	LL#1-4, IOB#1-5, AOB#1-2	Beginning before injection	Continuous	Continuous
	Annulus	LL#1-4, IOB#1-5, AOB#1-2	Beginning before injection	Continuous	Continuous
Injection Rate and Volume Monitoring		LL#1-4	N/A	Continuous	N/A
Fluid Sampling		LL#1-4	Once during well construction	N/A	N/A
		AOB#1-2	At least 3 sampling events prior to injection	Quarterly for first yr; Annually thereafter	Annually

Monitoring Activity/Test	Location	Baseline Frequency	Injection Period Frequency	Post-Injection Site Care Frequency
	UOB#1-4, All Shallow Groundwater Wells (10)	At least 3 sampling events prior to injection	Annually	Annually

D.1 Groundwater Quality Monitoring

To meet the requirements of 40 CFR 146.90(d), the Longleaf CCS Hub will monitor groundwater quality and variances in geochemical composition from formations above the confining zone throughout the operational period. Groundwater monitoring in one or more horizons between the confining zone(s) overlying the injection zone and the identified USDWs is required by 40 CFR 146.90(d). The purpose of such monitoring is to detect the presence of CO_2 migration out of the injection zone before it results in the impact of any USDW aquifer water quality.

During the PISC timeframe, Longleaf CCS Hub will monitor for groundwater quality and geochemical changes within the Upper Tuscaloosa Formation (above-zone formation) and Chickasawhay USDW as well as shallower sources of potable groundwater to meet the guidelines identified by 40 CFR 146.95(f)(3)(i).

Direct sampling of aqueous chemistry and related field parameters will be used to identify and quantify any potential impacts on USDW aquifers from a release of hypersaline waters and/or CO_2 from the injection zone. Locations for monitoring will include immediately above the primary confining zone in the Upper Tuscaloosa Formation for early leak detection (above-zone monitoring wells) as well as deep and shallow USDW aquifer monitoring. The ***Testing and Monitoring Plan*** satisfies the requirements detailed in 40 CFR 146.90(d) through the implementation of the groundwater monitoring plan which will provide extensive coverage in deep USDW and shallow groundwater monitoring wells.

D.2 Monitoring Location and Frequency

The locations of monitoring wells are planned on property leased in accordance with the Longleaf CCS Hub. Monitoring well locations are shown in **Figure 11** above and were chosen based on the expected development of the CO_2 plume and elevated pressure front, as discussed in the ***Testing and Monitoring Plan***.

Fluid sampling in all above-zone, deep USDW, and shallow USDW monitoring wells will begin with at least 3 sampling events collected over a time period of six months to a year prior to injection in order to establish a baseline. During injection, sampling will occur in above-zone monitoring wells quarterly for the first year and then annually thereafter until site closure. Fluid sampling will occur annually in deep and shallow USDW monitoring wells through the injection and PISC periods.

The details of the in-zone fluid sampling protocol are in the ***Testing and Monitoring Plan*** *and the* ***QASP***. **Table 2** summarizes the monitoring activities and frequencies for each monitoring location.

D.3 Analytical Parameters for Groundwater Quality Modeling

Table 3 shows the parameters that will be monitored along with the analytical methods that will be employed by the Longleaf CCS Hub during the collecting and analyzing of groundwater sampling results. Further details on the groundwater sampling parameters and methods can be found in the ***QASP***.

Table 3: Summary of Analytical and Field Parameters for Deep USDW Formation Fluid Samples.

Parameters	Analytical Methods
Deep USDW Monitoring Wells- Chickasawhay Formation	
Cations: Al, Ba, Mn, As, Cd, Cr, Cu, Pb, Sb, Se, and Tl	ICP-MS, EPA Method 6020B[1] or EPA Method 200.8[2]
Cations: Ca, Fe, K, Mg, Na, and Si	ICP-OES, EPA Method 6010D[3] or EPA Method 200.7[4]
Anions: Br, Cl, F, NO_3, and SO_4	Ion Chromatography, EPA Method 300.0[5]
Isotopes: S13C of DIC	Isotope ratio mass spectrometry
Dissolved CO_2 Total Dissolved Solids Water Density Alkalinity pH (field) Specific conductance (field) Temperature (field)	Coulometric titration, ASTM D513-16[6] Gravimetry, APHA 2540C[7] Oscillating body method APHA 2320B[8] EPA 150.1[9] APHA 2510[10] Thermocouple

[1] U.S. EPA. 2014. "Method 6020B (SW-846): Inductively Coupled Plasma-Mass Spectrometry." Revision 2. Washington, DC.
[2] U.S. EPA. 1994. "Determination of Trace Elements in Waters and Wastes by Inductively Coupled Plasma – Mass Spectrometry." Revision 5.4. Environmental Monitoring Systems Laboratory Office of Research and Development U.S. Environmental Protection Agency, Cincinnati, Ohio.
[3] U.S. EPA. 2014. "Method 6010D (SW-846): Inductively Coupled Plasma-Optical Emission Spectrometry." Revision 4. Washington, DC.
[4] U.S. EPA. 1994. "Determination of Trace Elements in Waters and Wastes by Inductively Coupled Plasma – Atomic Emission Spectrometry." Revision 4.4. Environmental Monitoring Systems Laboratory Office of Research and Development U.S. Environmental Protection Agency, Cincinnati, Ohio.
[5] U.S. EPA. 1993. "Method 300.0: "Methods for the Determination of Inorganic Substances in Environmental Samples." Revision 2.1. Washington, DC.
[6] ASTM Standard D513-16. 1988 (2016). "Standard Test Methods for Total and Dissolved Carbon Dioxide in Water," ASTM International, West Conshohocken, PA. DOI: 10.1520/D0513-16, www.astm.org
[7] American Public Health Association (APHA), SM 2540 C, "Standard Methods for the Examination of Water and Wastewater", APHA-AWWA-WPCF, 20th Edition (SDWA) and 21st Edition (CWA).
[8] Method 2320 B, Standard Methods for the Examination of Water and Wastewater, APHA-AWWA-WPCF, 21st Edition, 1997.
[9] U.S. EPA. 1971 (1982). "Method 150.1: pH in Water by Electromagnetic Method", Cincinnati, OH.
[10] American Public Health Association (APHA), SM2510, 1992. Standard Methods for the Examination of Water and Wastewater", APHA-AWWA-WPCF, 18th Edition, 1992.

D.4 CO_2 Plume and Pressure Front Tracking

Pressure monitoring will be conducted through a combination of five in-zone monitoring wells as well as converted injections wells completed in the targeted injection interval in conjunction with two above-zone monitoring wells that will be completed in the first porous and permeable zone in the Upper Tuscaloosa Formation above the primary confining interval, the Tuscaloosa Marine Shale. This monitoring will be carried out for the duration of the PISC period. The objective during this phase is to collect storage zone pressure data to provide quality control and assurance for the numerical models and to detect anomalous above-zone pressure increases that could indicate the potential of upward migration of CO_2 into the overlying USDWs.

Continuous monitoring of pressure will be conducted via the planned in-zone and above-zone monitoring wells in conjunction with the proposed injection wells over the course of the active injection period. Continuous pressure monitoring will continue in the in-zone and above-zone monitoring wells through the PISC period until site closure. Pressure gauges will be removed from monitoring wells only as maintenance is required or deemed necessary through the scope of other well maintenance activities.

Indirect CO_2 plume monitoring will occur using PNC logs and vertical seismic profile surveys (VSPs) in conjunction with DAS to monitor formation fluid saturations (including the presence of CO_2) and track the movement of the CO_2 plume in the injection interval.

The CO_2 plume and pressure front will continue to be monitored for an additional 20 years after injection stops, in accordance with the proposed alternative PISC timeframe detailed previously. The groundwater quality and geochemistry monitoring through the above-zone wells will occur annually throughout the PISC timeframe, while direct pressure monitoring via the in-zone monitoring wells will continue until site closure. PNC logging and VSPs will continue every 5 years during the PISC period to continue to monitor the CO_2 plume.

D.5 Schedule for Submitting Post-Injection Monitoring Results

The methods and frequencies of monitoring procedures to be carried out during the post-injection phase are outlined in Table 2. As described in Section K of the ***Testing and Monitoring Plan***, the results of any MIT or well workover will be reported to the UIC Program Director within 30 days of occurrence, and the results of monitoring activities will be provided to the UIC Program Director in semi-annual reports.

D.6 Updating PISC and Site Closure Plan

Required revisions to PISC and Site Closure Plan will be submitted to the EPA within 30 days of the revision.

E. Site Closure Plan

Closure of the site will begin at the end of the approved PISC timeframe. These activities will include the decommissioning of surface equipment, plugging monitoring wells, restoring of the site to pre-operational conditions, and preparing and submitting all documentation necessary to demonstrate that site closure has been carried out.

The following is required prior to site closure activities (40 CFR 146.93(d)):

- *Notice of Intent for Site Closure*: Longleaf CCS, LLC shall notify EPA Region 4 UIC Branch at least 120 days in advance of commencing site closure activities. Any revisions to the Post-Injection Site Care and Site Closure Plan shall be submitted to EPA with this notice. If revision of the plan is not necessary, Longleaf CCS, LLC shall demonstrate this through monitoring data and modeling results (40 CFR 146.93(a)(3)). Site closure activities shall not commence until EPA authorization is received.

E.1 Equipment Decommissioning

Surface equipment decommissioning is planned to occur in two phases: the first phase will occur after the active injection phase, and the second phase will take place at the end of the PISC period. Monitoring of the plume will continue at the end of the active injection phase, but there will no longer be a need for the pumping and other control equipment on location. All unnecessary equipment and temporary facilities, if applicable, will be broken down and removed. This works toward clearing space on location as well as enabling surface site reclamation processes that can begin in areas that are no longer impacted by continuing operations.

All equipment and facilities that will be utilized through the duration of the PISC period will remain on location. This includes all equipment associated with the collection of data from monitoring wells as well as other monitoring stations.

E.2 Site Closure and Well Plugging Plan

The well plugging program is designed to prevent communication between the injection reservoir and overlying USDWs. The injection and in-zone monitoring wells will have a direct connection between the injection interval and ground surface. Because of this, they will be plugged and abandoned using industry best practices in order to prevent any upward migration of CO_2 or other formation fluids to USDWs upon site closure. Details of injection well plugging are provided in the ***Injection Well Plugging Plan***.

CO_2-resistant cement will be used to plug access across the injection interval, with the well then being completely filled with cement, in staged increments, to prevent fugitive movement of CO_2 through the wellbore.

Internal and external integrity of the wells will be confirmed through the utilization of cement-bond, temperature, and/or noise logs prior to them being plugged. Additionally, a pressure test will be conducted above the perforated intervals, where present, to confirm well integrity. The results of the logging and testing will be approved before well plugging operations are to commence.

E.3 Site Restoration

At the end of the active injection phase, all acreage that has been disturbed as a result of operations will be reclaimed and returned to its pre-development condition. Any gravel pads, access roads, and surface facilities will be removed, and the land will be reclaimed for agricultural or other pre-development utilization unless the landowner requests that rock or fencing are to remain.

E.4 Site Closure Reporting

The following submittals are required for site closure (40 CFR 146.93(f)):

- *Survey Plat*: A survey plat indicating the location of the injection well relative to permanently surveyed benchmarks shall be submitted to both Mobile County and the EPA Region IV Administrator.
- Site *Closure Report*: Upon completion of site closure activities, Longleaf CCS, LLC will submit a report to the UIC Program Director within 90 days. The report shall include documentation of injection and monitoring well plugging as specified in 40 CFR 146.92, copy of the survey plat, documentation of appropriate notification to the Alabama Oil and Gas Board (see Section C.2 of the ***Injection Well Plugging Plan***), and records reflecting the nature, composition, and volume of the CO_2 stream. This report shall be retained by Longleaf CCS, LLC for a 10-year period.

Additionally, Longleaf CCS, LLC shall record a notation on the deed to the facility property that includes that the land has been used to sequester CO_2, name and address of the agencies to which the survey plat was submitted, and the volume of fluid injection, the injection zones into which it was injected, and the period over which injection occurred (40 CFR 146.93(f)(1)).

Post-Injection Site Care and Site Closure records will be retained for 10 years after closure has been completed. At the conclusion of this 10-year period, these records will be delivered to the UIC Program Director.

Longleaf CCS Hub

Longleaf CCS LLC

Appendix

Quality Assurance and Surveillance Plan

40 CFR 146.90(k)

Appendix to the Testing and Monitoring Plan

Facility Information

Facility Name: Longleaf CCS Hub

Facility Contact: Longleaf CCS, LLC
14302 FNB Parkway
Omaha, NE 68154

Well Locations: Mobile County, Alabama

LL#1: Latitude: 31.071303° N
Longitude: -88.094703° W

LL#2: Latitude: 31.070774° N
Longitude: -88.074523° W

LL#3: Latitude: 31.0447129° N
Longitude: -88.0736318° W

LL#4: Latitude: 31.0569516° N
Longitude: -88.1047433° W

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List of Acronyms/Abbreviations

AoR	Area of Review
CCS	Carbon capture and storage
CO_2	Carbon dioxide
CMG	Computer Modelling Group
DOE	Department of Energy
DAS	Distributed Acoustic Sensing
DTS	Distributed Temperature Sensing
EPA	Environmental Protection Agency
ERRP	Emergency and Remedial Response
ft	Feet
LL	Longleaf
mg/l	Milligrams per liter
MIT	Mechanical Integrity Test
MMcf/d	Million cubic feet/day
mol%	Percentage of total moles in a mixture made up by one constituent
msl	Mean sea level
mt	Metric tons
Mt	Millions of metric tons
mt/d	Metric tons per day
mt/y	Metric tons per day
MT/y	Millions of metric tons per year
PISC	Post-Injection Site Care
PNC	Pulsed Neutron Capture Log
ppmv	Parts per million volume
psi	Pounds per square inch, gauge
psia	Pounds per square inch, absolute
psi/ft	Pounds per square inch per foot
SS	Sub- Sea
TVD	True Vertical Depth
UIC	Underground Injection Control
USDW	Underground Source of Drinking Water

A. Project Management

A.1. Project/Task Organization

A.1.a/b Key Individuals and Responsibilities

The project will be owned and operated by Longleaf CCS, LLC who will serve as the lead on all project tasks while supervising the performance of subcontractors when required for individual tasks. Tasks which are related to testing and monitoring at the Longleaf CCS Hub that will require supervision for purposes of quality control and assurance are broadly divided into:

1. Groundwater Sampling and Analysis
2. Well Logging
3. Mechanical Integrity Testing
4. Injection Monitoring
5. CO_2 Stream Sampling and Analysis
6. Geophysical Monitoring

A.1.c Independence from Project Quality Assurance (QA) Manager and Data Gathering

Most of the physical samples collected and other data gathered as part of the testing and monitoring program will be analyzed, processed, or witnessed by third parties independent and outside of the project management structure. Longleaf CCS, LLC will provide the UIC Program Director with the name and credentials of any vendors, subcontractors, or testing laboratories used for testing and monitoring protocols during each semi-annual reporting period (see Section *K.1* in the *Testing and Monitoring Plan*).

A.1.d QA Project Plan Responsibility

Longleaf CCS, LLC will be responsible for maintaining and distributing the official, approved *Quality Assurance Surveillance Plan (QASP)*. Longleaf CCS, LLC will periodically review this *QASP* and consult the UIC Program Director if/when changes to the plan are warranted.

A.2. Problem Definition/Background

A.2.a Reasoning

The Longleaf CCS Hub *Testing and Monitoring Plan* MVA program has operational monitoring, verification, and environmental monitoring components. Operational monitoring is used to ensure safety and protection of USDWs with all procedures associated with fluid injection, monitoring the response of the injection interval at the wellsite, and the movement of the CO_2 plume and pressure front. Key monitoring parameters include: downhole pressure, wellhead pressure, flow rate, annulus pressure and fluid volume, and above-zone fluid chemistry. Other monitoring parameters include well temperature profile and acoustic sensing. The verification component of the *Testing and Monitoring Plan* will provide data to evaluate if leakage of CO_2 through the caprock or wellbores is occurring. This includes pressure monitoring, PNC loging, temperature monitoring, vertical seismic profile surveys (VSPs), formation fluid monitoring in the above-zone interval, and groundwater monitoring in deep and shallow USDWs. Pressure and geophysical data will be used to validate the geologic and reservoir models.

The objective of the Longleaf CCS Hub *Testing and Monitoring Plan* is to demonstrate that project activities do not endanger the environment or human health. To achieve this goal, this *QASP* was developed to ensure the quality and standards of the testing and monitoring program and to specifically meet the requirements of 40 CFR 146.90(k).

A.2.b Reasons for Initiating the Project

The objective of the Longleaf CCS Hub is to develop a safe and commercially viable CO_2 storage site available to CO_2 emitters in the Mobile, Alabama region.

A.2.c Regulatory Information, Applicable Criteria, Action Limits

Longleaf CCS, LLC is required to perform several types of activities during the lifetime of the CO_2 storage project in order to ensure that the injection wells maintain their mechanical integrity, that fluid migration and operating pressures are within the limits described in the permit application, and that there is negligible threat to USDWs, public health and safety, and the local environment. Monitoring procedures included well MITs, injection pressure and rate monitoring, CO_2 plume and pressure front tracking, and groundwater quality testing (full details of monitoring activities are provided in the *Testing and Monitoring Plan*). This *QASP* discusses data measurement methods as well as the steps Longleaf CCS, LLC will take to ensure that the quality of all gathered samples and data provide confidence in making project decisions and protecting USDWs.

A.3. Project/Task Description.

A.3.a Summary of Work to be Performed

Table 1 describes the testing and monitoring activities, location, and purpose. **Figure 1** displays the surface locations of all injection and monitoring wells, and **Figure 2** displays the stratigraphic locations of all injection and monitoring wells.

Table 1: Summary of Testing and Monitoring

Activity	Location(s)	Method	Analytical Technique	Purpose
CO_2 stream analysis	Master meter at LL#2 well site	Gas chromatograph and physical sampling	Chemical analysis	Analysis of injectate 40 CFR 146.90(a)
Corrosion monitoring	Post-compression and dehydration	Corrosion coupons	Chemical analysis	Corrosion monitoring 40 CFR 146.90(c)
Groundwater quality	AOB#1-2 UOB#1-4 Shallow USDW wells (10)	Kuster Flow Sampler (AOB and UOB wells) and shallow groundwater sampling (ASTM-D4448[1])	Chemical analysis	Groundwater and geochemistry monitoring 40 CFR 146.90(d)
Injection rate and volume	LL#1-4 wellheads	Flow meter	Continuous direct measurement	Continuous monitoring of injection rate and volume 40 CFR 146.90(b)
Injection pressure	LL#1-4 wellheads	Wellhead pressure/ temperature gauge	Continuous direct measurement	Continuous monitoring of injection pressure 40 CFR 146.90(b)
Annular pressure	LL#1-4 wellheads	Annular pressure gauge	Continuous direct measurement	Continuous monitoring of annular pressure 40 CFR 146.90(b)

[1] American Society for Testing and Materials (ASTM) Standard D4448-01(2019). Standard Guide for Sampling Ground-Water Monitoring Wells, ASTM International , West Conshohocken, PA. DOI: 10.1520/D4448-01R19, www.astm.org.

Activity	Location(s)	Method	Analytical Technique	Purpose
Annular Volume	LL#1-4 wellheads	Annular volume gauge	Continuous direct measurement	Continuous monitoring of annulus fluid volume 40 CFR 146.90(b)
Downhole pressure/ temperature	LL#1-4 IOB#1-5 AOB#1-2	Downhole gauges	Direct measurement	Continuous monitoring of injection zone pressure and temperature 40 CFR 146.90(g)(1)
Mechanical integrity	LL#1-4 IOB#1-5 AOB#1-2	Internal – Annular pressure gauge monitoring LL#1-4 only	Direct measurement	Demonstration of internal and external mechanical integrity of the wellbore 40 CFR 146.90(e)
		External – DTS	Distributed indirect measurement	
Pressure falloff testing	LL#1-4	Pressure gauge	Direct measurement	Pressure falloff testing 40 CFR 146.90(f)
CO_2 plume and pressure front monitoring	LL#1-4 IOB#1-5 AOB#1-2	Downhole pressure and temperature gauges, PNC logs, and VSPs.	Direct and indirect measurements	Plume and pressure front tracking 40 CFR 146.90(g)

A.3.b Frequency of Work to be Performed

Table 2 describes the frequency of testing and monitoring activities.

Table 2: Testing and Monitoring Frequency

Monitoring Activity/Test		Location	Baseline Frequency	Injection Period Frequency	Post-Injection Site Care Frequency
CO_2 Injection Stream Analysis		Master meter at LL#2 well site	Begin before injection	Continuous/ Quarterly	N/A
Corrosion Monitoring		Post-compression and dehydration	Establish coupon baseline	Quarterly	N/A
Fiber Optic / Seismic Monitoring	Distributed Acoustic Sensing (DAS)	LL#1-4, IOB#1-5, AOB#1-2	Beginning before injection	Continuous	Continuous
	Distributed Temperature Sensing (DTS)	LL #1-4, IOB #1-5, AOB #1-2	Beginning before injection	Continuous	Continuous

<table>
<tr><th colspan="2">Monitoring Activity/Test</th><th>Location</th><th>Baseline Frequency</th><th>Injection Period Frequency</th><th>Post-Injection Site Care Frequency</th></tr>
<tr><td colspan="2">Pulsed Neutron Capture Log (PNC)</td><td>LL#1-4,
IOB#1-5,
AOB#1-2</td><td>Once before injection</td><td>3yrs after injection begins; Every 5yrs after</td><td>At end of injection; Every 5yrs after</td></tr>
<tr><td colspan="2" rowspan="2">Mechanical Integrity Tests</td><td>LL#1-4,
IOB#1-5</td><td>Once before injection</td><td>Annually</td><td>Annually</td></tr>
<tr><td>AOB#1-2,
UOB#1-4</td><td>Once before injection</td><td>Every 5yrs</td><td>Every 5yrs</td></tr>
<tr><td colspan="2">Pressure Transient Test</td><td>LL#1-4</td><td>Once before injection</td><td>3yrs after injection begins; Every 5yrs after</td><td>At end of injection; Every 5yrs after</td></tr>
<tr><td colspan="2">Flow Profile Survey</td><td>LL#1-4</td><td>N/A</td><td>Every 5yrs</td><td>N/A</td></tr>
<tr><td colspan="2">Bottomhole Pressure Monitoring</td><td>LL#1-4,
IOB#1-5,
AOB#1-2</td><td>Beginning before injection</td><td>Continuous surface read-out</td><td>Continuous surface read-out</td></tr>
<tr><td rowspan="2">Wellhead Pressure Monitoring</td><td>Tubing</td><td>LL#1-4,
IOB#1-5,
AOB#1-2</td><td>Beginning before injection</td><td>Continuous</td><td>Continuous</td></tr>
<tr><td>Annulus</td><td>LL#1-4,
IOB#1-5,
AOB#1-2</td><td>Beginning before injection</td><td>Continuous</td><td>Continuous</td></tr>
<tr><td colspan="2">Injection Rate and Volume Monitoring</td><td>LL#1-4</td><td>N/A</td><td>Continuous</td><td>N/A</td></tr>
<tr><td colspan="2" rowspan="3">Fluid Sampling</td><td>LL#1-4,
IOB#1-5</td><td>Once during well construction</td><td>N/A</td><td>N/A</td></tr>
<tr><td>AOB#1-2</td><td>At least 3 sampling events prior to injection</td><td>Quarterly for first yr; Annually thereafter</td><td>Annually</td></tr>
<tr><td>UOB#1-4,
All Shallow Groundwater Wells (10)</td><td>At least 3 sampling events prior to injection</td><td>Annually</td><td>Annually</td></tr>
</table>

A.3.c Geographic and Stratigraphic Locations

Figure 1 displays the surface locations of all injection and monitoring wells, including in-zone (5 wells), above-zone (2 wells), deep USDW (4 wells), and shallow USDW (10) monitoring wells. Shallow USDW wells will be located on each existing wellpad in the Longleaf CCS Hub.

Figure 2 displays the stratigraphic locations of all injection and monitoring wells. Injection wells and in-zone monitoring wells will be completed in the Paluxy Formation at an approximate depth of 10,080 ft MSL. Above-zone monitoring wells will be completed in the first porous and permeable interval in the Upper Tuscaloosa Formation that is above the primary confining layer, the Tuscaloosa Marine Shale, at an approximate depth of 7,250 ft MSL. Deep USDW monitoring wells will be completed in the lowest most USDW, the Chicasawhay Formation, at an approximate depth of 1,700 ft MSL. Shallow USDW monitoring wells will be completed within a near-surface freshwater source.

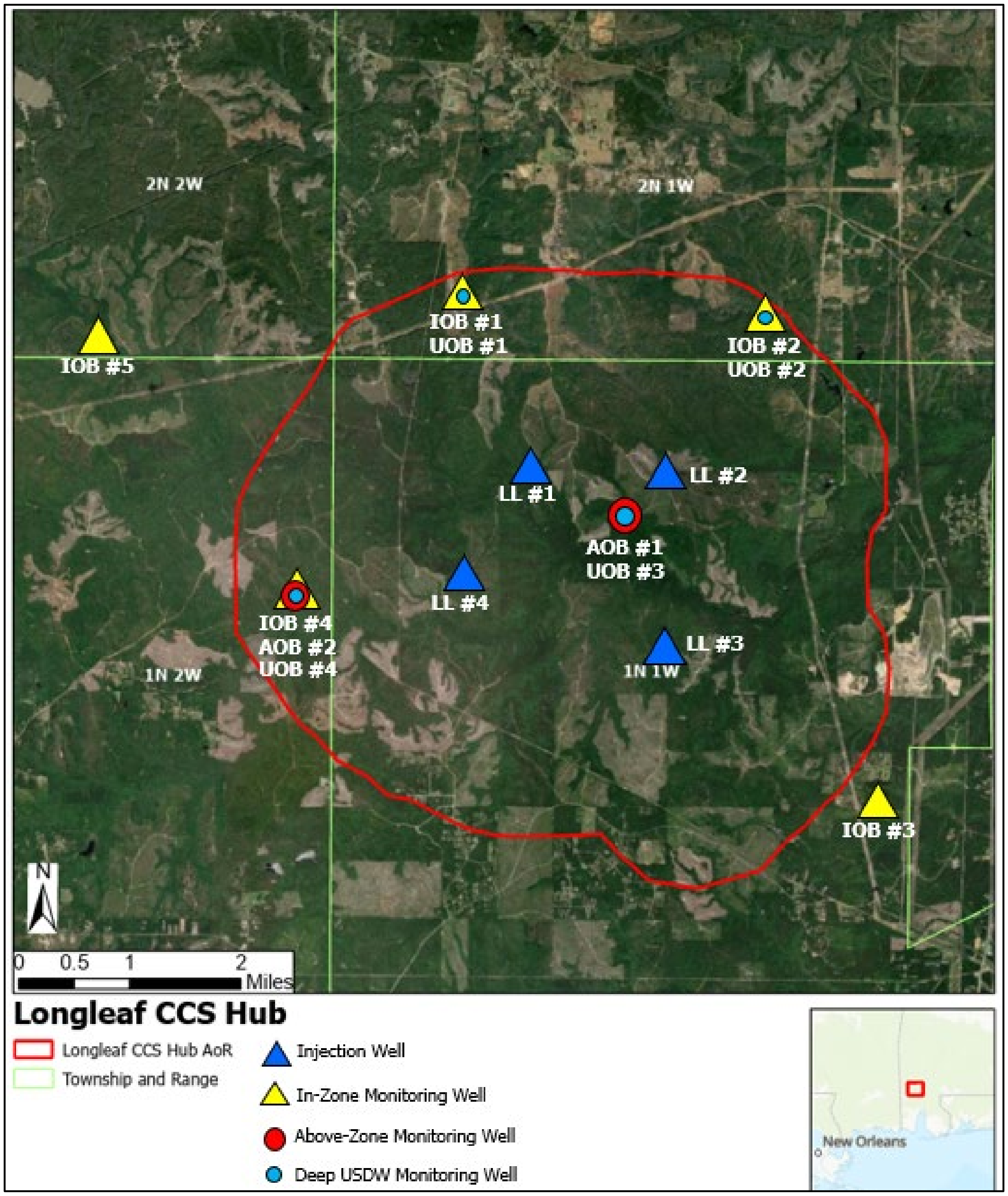

Figure 1: Locations of Proposed Injection and Monitoring Wells at the Longleaf CCS Hub.

Note: Shallow USDW monitoring wells are located on each well pad (10 total).

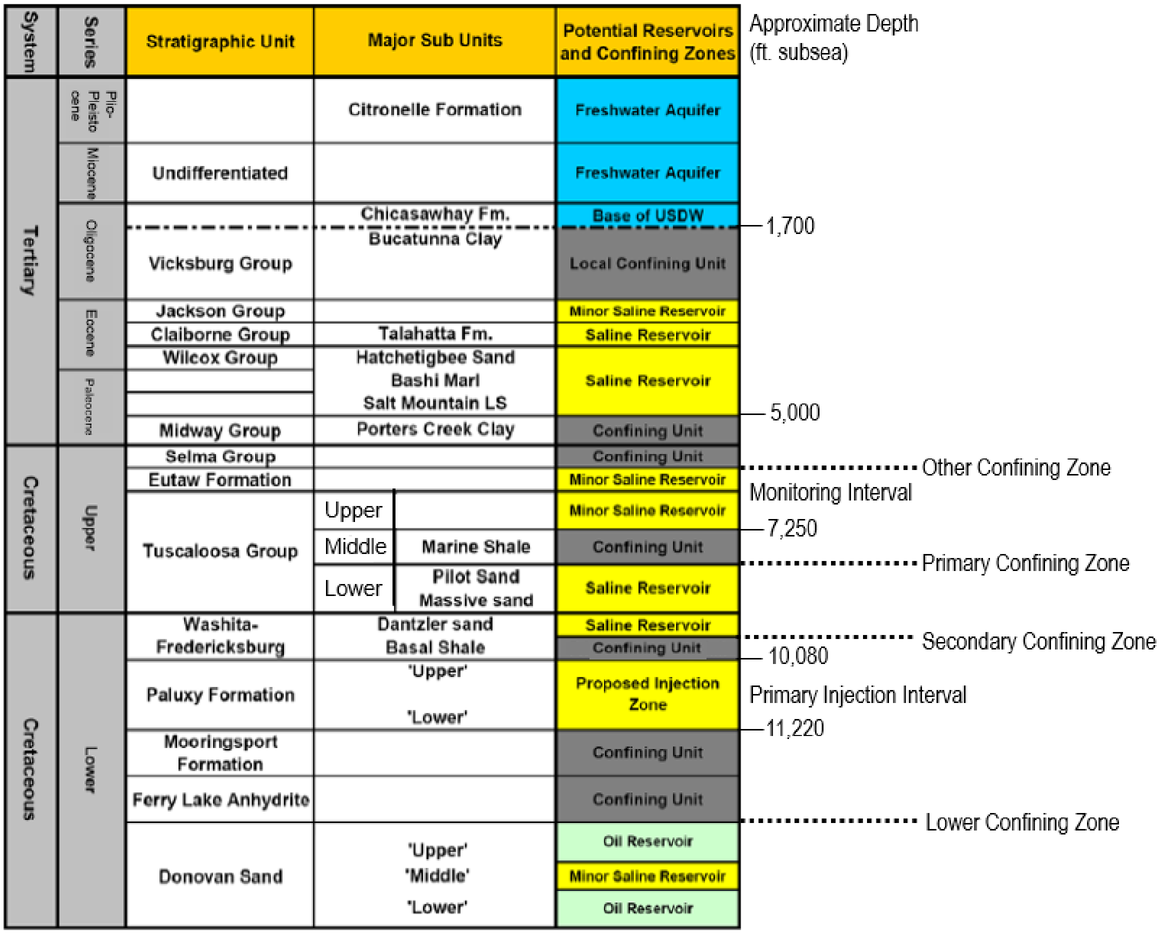

Figure 2: Geologic Stratigraphic Column at the Longleaf CCS Hub (modified from Pashin et al., 2008).[2]

A.4. Quality Objectives and Criteria

A.4.a Performance/Measurement Criteria

The overall objective for this *QASP* is to develop and implement procedures for subsurface monitoring, field sampling, laboratory analysis, and reporting which will provide results to meet the characterization and non-endangerment goals of the Longleaf CCS Hub. Please refer to **Table 3** through **Table 8** for specifications and action limits of technologies used for Longleaf CCS Hub testing and monitoring.

[2] Pashin, J. C, McIntyre, M. R., Grace, R. L. B., Hills, D. J., “Southeastern Regional Carbon Sequestration Partnership (SECARB) Phase III, Final Report”, Report to Advanced Resources International by Geological Survey of Alabama, Tuscaloosa, September 12, 2008

Table 3: Summary of Analytical and Field Parameters for Shallow USDW, Deep USDW, and Above-Zone Fluid Sampling

Parameters	Analytical Methods[3]	Detection Limit/Range	Typical Precisions	QC Requirements
Cations: Al, Ba, Mn, As, Cd, Cr, Cu, Pb, Sb, Se, and Tl	ICP-MS EPA Method 6020B[4] or EPA Method 200.8[5]	0.001 to 0.1 mg/L (analyte, dilution and matrix dependent)	±15%	Daily Calibration; blanks, duplicates and matrix spikes at 10% or greater frequency
Cations: Ca, Fe, K, Mg, Na, and Si	ICP-OES EPA Method 6010D[6] or EPA Method 200.7[7]	0.005 to 0.5 mg/L (analyte, dilution and matrix dependent)	±15%	Daily Calibration; blanks, duplicates and matrix spikes at 10% or greater frequency
Anions: Br, Cl, NO_3, and SO_4	Ion Chromatography EPA Method 300.0[8]	0.02 to 0.13 mg/L (analyte, dilution and matrix dependent)	±15%	Daily Calibration: blanks and duplicates at 10% or greater frequency
Dissolved CO_2	Coulometric Titration ASTM 513-16[9]	25 mg/L	±15%	Duplicate measurement; standards at 10% or greater frequency
Total Dissolved Solids	Gravimetry APHA 2540C[10]	12 mg/L	±15%	Balance calibration, duplicate analysis
Alkalinity	APHA 2320B[11]	4 mg/L	±3 mg/L	Duplicate Analysis
pH (field)	EPA 150.1[12]	2 to 12 pH units	±0.2 pH unit	User Calibration per manufacturer recommendation

[3] An equivalent method may be employed with the prior approval of the UIC Program Director
[4] U.S. EPA. 2014. "Method 6020B (SW-846): Inductively Coupled Plasma-Mass Spectrometry." Revision 2. Washington, DC.
[5] U.S. EPA. 1994. "Determination of Trace Elements in Waters and Wastes by Inductively Coupled Plasma – Mass Spectrometry." Revision 5.4. Environmental Monitoring Systems Laboratory Office of Research and Development U.S. Environmental Protection Agency, Cincinnati, Ohio.
[6] U.S. EPA. 2014. "Method 6010D (SW-846): Inductively Coupled Plasma-Optical Emission Spectrometry." Revision 4. Washington, DC.
[7] U.S. EPA. 1994. "Determination of Trace Elements in Waters and Wastes by Inductively Coupled Plasma – Atomic Emission Spectrometry." Revision 4.4. Environmental Monitoring Systems Laboratory Office of Research and Development U.S. Environmental Protection Agency, Cincinnati, Ohio.
[8] U.S. EPA. 1993. "Method 300.0: "Methods for the Determination of Inorganic Substances in Environmental Samples." Revision 2.1. Washington, DC.
[9] ASTM Standard D513-16. 1988 (2016). "Standard Test Methods for Total and Dissolved Carbon Dioxide in Water," ASTM International, West Conshohocken, PA. DOI: 10.1520/D0513-16, www.astm.org
[10] American Public Health Association (APHA), SM 2540 C, "Standard Methods for the Examination of Water and Wastewater", APHA-AWWA-WPCF, 20th Edition (SDWA) and 21st Edition (CWA).
[11] Method 2320 B, Standard Methods for the Examination of Water and Wastewater, APHA-AWWA-WPCF, 21st Edition, 1997.
[12] U.S. EPA. 1971 (1982). "Method 150.1: pH in Water by Electromagnetic Method", Cincinnati, OH.

Parameters	Analytical Methods[3]	Detection Limit/Range	Typical Precisions	QC Requirements
Specific Conductance (field)	APHA 2510[13]	0 to 200 mS/cm	±1% of reading	User calibration per manufacturer recommendation
Temperature (field)	Thermocouple	-5 to 50ºC	±0.2ºC	Factory Calibration
Isotopes: $\delta^{13}C$ of DIC	Isotope Ratio Mass Spectrometry	12.2mg/L HCO_3^- for $\delta^{13}C$	±0.15% for $\delta^{13}C$	10% duplicates; 4 standards/batch

Abbreviations: ICP=inductively coupled plasma; MS= mass spectrometry; OES= Optical emission spectrometry; GC-P=Gas chromatography-Pyrolysis

Table 4: Summary of Analytical Parameters for CO_2 Stream

Parameters	Method	Detection Limit/Range	Typical Precisions	QC Requirements
CO_2 Purity	ISBT 2.0 Caustic absorption Zahm-Nagel or online gas quality equipment	99.00% to 99.99%	± 10 % of reading	User calibration per manufacturer
Water Content	Online gas quality equipment	To be updated with manufacturer specifications	To be updated with manufacturer specifications	To be updated with manufacturer specifications
Total Hydrocarbons	ISBT 10.0 THA (FID) or online gas quality equipment	1 uL/L to 10,000 uL/L (ppm by volume)	5 - 10 % of reading relative across the range	daily blank, daily standard within 10 % of calibration, secondary standard after calibration
Inert Gases (N_2, Ar, O_2)	ISBT 4.0 (GC/DID) GC/TCD or online gas quality equipment	1 uL/L to 5,000 uL/L (ppm by volume)	± 10 % of reading	daily standard within 10 % of calibration, secondary standard after calibration
Alcohols, aldehydes, esters	ISBT 11.0 (GC/FID) or online gas quality equipment	0.1 uL/L to 100 uL/L (ppm by volume)- dilution dependent	5 - 10 % of reading relative across the range	daily blank, daily standard within 10 % of calibration, secondary standard after calibration
Hydrogen Sulfide	ISBT 14.0 (GC/SCD) or online gas quality equipment	0.1 uL/L to 100 uL/L (ppm by volume)- dilution dependent	5 - 10 % of reading relative across the range	daily blank, daily standard within 10 % of calibration, secondary standard after calibration
Total Sulfur	ISBT 14.0 (GC/SCD) or online gas quality equipment	0.01 uL/L to 50 uL/L (ppm by volume)- dilution dependent	5 - 10 % of reading relative across the range	daily blank, daily standard within 10 % of calibration, secondary standard after calibration

[13] American Public Health Association (APHA), SM2510, 1992. Standard Methods for the Examination of Water and Wastewater", APHA-AWWA-WPCF, 18th Edition, 1992.

Parameters	Method	Detection Limit/Range	Typical Precisions	QC Requirements
Oxygen	ISBT 4.0 (GC/DID) GC/TCD or online gas quality equipment	1 uL/L to 5,000 uL/L (ppm by volume)	± 10 % of reading	daily standard within 10 % of calibration, secondary standard after calibration
Carbon Monoxide	ISBT 5.0 Colorimetric ISBT 4.0 (GC/DID) or online gas quality equipment	5 uL/L to 100 uL/L (ppm by volume)	± 20 % of reading	duplicate analysis

Note: Analytical parameters presented are for physical bottle sampling and laboratory analysis. A gas chromatograph will be installed to continuously detect CO_2 purity, total hydrocarbons, inert gases, hydrogen, alcohols, oxygen, carbon monoxide, and glycol. Quarterly bottle analysis will be performed to analyze the CO_2 stream for hydrogen sulfide and total sulfur. The detection range, accuracy, precision, and calibration requirements of the gas chromatograph will be shared with the UIC Program Director as requested.

Table 5: Specifications for MIT Testing and and Geophysical Monitoring Technology

Logging Tool	Analytical Methods	Detection Limit/Range	Typical Precisions	QC Requirements	Calibration Frequency
Ultrasonic Cement Bong Log (SLB USI Tool)	Vendor best practice	0-10 MRayl	±0.5 MRayl	Vendor Calibration (3rd party)	Per Vendor Discretion
PNC Logging (SLB Pulsar and RST Tool)	Vendor best practice	Porosity: 0 to 60 pu	TBD	Vendor Calibration (3rd party)	Per Vendor Discretion
Distributed Temperature Sensing	Vendor best practice	-40ºF to 149ºF	0.01ºC	Vendor Calibration (3rd party)	Per Vendor Discretion

Table 6: Summary of Analytical Parameters for Coupon Corrosion Monitoring

Parameters	Analytical Methods	Detection Limit/Range	Typical Precisions	QC Requirements
Mass	NACE RP0775-2018[14]	.005 mg	±2%	Annual Calibration of Scale (3rd Party)
Thickness	NACE RP0775-2018	.001 mm	±.005 mm	Factory calibration

[14] The National Association of Corrosion Engineers (NACE) Standard RP0775, (2018). *Preparation, Installation, Analysis, And Interpretation of Corrosion Coupons In Oilfield Operations*, Houston, TX. ISBN 1-57590-086-6.

Table 7: Summary of Measurement Parameters for CO_2 Injection Process Monitoring

Parameters	Methods	Detection Limit/Range	Vendor Specified Accuracy	QC Requirements	Calibration Frequency
Operational Annular Pressure Monitoring	ISO/IEC 17025 (2017)	0-3,000 psi	± .5% FS	Annual Calibration of Scale (3rd party)	As suggested by control system/gauge manufacturer
Wellhead Injection pressure (*e.g. PPS PPS31 Wellhead Pressure Logger or similar product*)	ISO/IEC 17025 (2017)	0-5,000 psi	±0.03% FS	Annual Calibration of Scale (3rd party)	As suggested by gauge manufacturer
Injection mass flow rate (*e.g. Emerson Coriolis mass flow meter or similar product*)	AGA Report 3 API Chapter 14 Part 3[15]	547.95-3,561.64 mt/day	±0.1% of rate for liquid ±0.35% of rate for gas	Annual Calibration of Scale (3rd party)	As suggested by gauge manufacturer
Downhole Temperature (*e.g. Baker Hughes SureSENS QPT ELITE pressure/temperature gauge or similar product*)	Unknown	77 ºF to 302 ºF	0.27 ºF	Initial Manufacturer Calibration	Not required on downhole gauges
Downhole Pressure (*e.g. Baker Hughes SureSENS QPT ELITE pressure/temperature gauge of similar product*)	Unknown	200 psi to 10,000 psi	± 0.015% FS	Initial Manufacturer Calibration	Not required on downhole gauges

[15] API MPMS Ch. 14 / AGA Report No. 3: Orifice Metering of Natural Gas and Other Related Hydrocarbon Fluids – Concentric, Square-edged Orifice Meters, 2016.

Table 8: Actionable Testing and Monitoring Outputs

Activity or Parameter	Project Action Limit	Detection Limit	Anticipated Reading
DTS	Action to be taken when a temperature anomaly is observed	Refer to Table 5	Difference between profiles observed during baseline & injection stream temperature
PNC logging	Action to be taken when a CO_2 saturation anomaly is observed	Refer to Table 5	Brine saturated ~ 60 cu CO_2 saturated ~ 8 cu
DAS	Action to be taken when an acoustic anomaly is observed	Refer to Table 5	Baseline and injection noise
Injection rate	Injection rate is reduced if max instantaneous rate of 4,110 mt/d is reached	Refer to Table 7	Averaging 3,425 mt/d
Surface/downhole pressure	Injection stops if MASP is reached or 90% fracture pressure downhole is reached	Refer to Table 7	< 2,000 psi at surface < 6,400 psi downhole (see *Injection Well Operations Plan)*
Annular pressure	<3% pressure loss over 1 hour	Refer to Table 5	>3% pressure loss over 1 hour
Annular volume	10% loss of annular volume or continuous fluid make up exceeding 24 hours	Tank fluid level indicator	Annular fluid make up is expected when temperature of the fluid changes
Annular pressure/volume	Action to be taken when annulus pressure is below 250 psi, above 500 psi, or less than injection pressure downhole in injection wells	Refer to Table 7	250-500 psi at surface Volume TBD during baseline
Above-zone water quality (fluid sampling)	Action to be taken when chemical profile anomaly is observed	Refer to Table 3	Profiles TBD during baseline
Above-confining-zone pressure	Action will be taken when a pressure/temperature anomaly occurs	Refer to Table 3	Profiles TBD during baseline
CO_2 plume monitoring	Action to be taken if CO_2 plume is observed outside of expected/modelled spatial limits/geologic intervals	Dependent on geologic conditions	Profiles TBD during baseline

A.4.b Precision

For groundwater sampling, data accuracy will be assessed by the collection and analysis of field blanks to test sampling procedures and matrix spikes to test lab procedures. Field blanks will be taken no less than one per sampling event to spot check for sample bottle contamination. Assessment of analytical precision will be the responsibility of the individual laboratories. Third party laboratories used will be EPA approved and certified laboratories.

A.4.c Bias

Assessment of analytical bias is to be the responsibility of the individual laboratories per their standard operating procedures and analytical methodologies.

A.4.d Representativeness

Data representativeness is the degree to which data accurately and precisely represent a characteristic of a population, parameter variations at a sampling point, a process condition, or an environmental condition. The Longleaf CCS Hub sampling network has been designed to provide data representative of site-specific conditions. For analytical results of individual groundwater samples, representativeness will be estimated by ion and mass balances. Ion balances within ±10% error or less will be considered valid. Mass balance assessment will be used in cases where the ion balance is greater than ±10% to help identify the source of error. For a sample and its duplicate, if the relative percent difference is greater than 10%, the sample may be considered non-representative.

A.4.e Completeness

Data completeness is a measure of the quantity of valid data obtained from a measurement system compared to the quantity that was expected to be obtained under normal conditions. It is anticipated that data completeness of 90% for groundwater sampling will be acceptable to meet monitoring goals. In cases of direct pressure and temperature measurements, it is expected that data will be recorded no less than 90% of the time.

A.4.f Comparability

Data comparability is the confidence with which one data set can be compared to another. The data sets generated by the Longleaf CCS Hub will be done so in accordance with a consistent methodology so that each data set is directly comparable to another. This allows for appropriate data comparison and identification of anomalies, if present.

To ensure appropriate QA/QC standards, direct pressure, temperature, and logging measurements obtained through the proposed operations will be directly comparable to data previously obtained.

A.4.g Method Sensitivity

Table 9 summarizes the representative logging tool specifications. **Table 10** through **Table 13** provide additional details on gauge specifications and sensitivities.

Table 9: Representative Logging Tool Specifications

Parameter	Ultrasonic Imager Log	PNC/Reservoir Saturation Tool	DAS	DTS	Pulsar
Logging speed	1,800 ft/hr	150 ft/hr	NA	NA	1,000 ft/hr
Vertical resolution	6 inches	24 inches	*25cm	*25-50 cm	15 inches
Investigation	Casing-to-cement interface	4-6 inches	*0-24.8 miles	At fiber location	10-16 inches
Temperature rating	350°F (175°C)	300°F (150°C)	500°F	149ºF	350°F (175°C)
Pressure rating	20,000 psi	15,000 psi	20,000 psi	20 psi	15,000 psi

Table 10: Pressure and Temperature—Downhole Gauge Vendor Specifications

Parameter	Value
Calibrated working pressure range	200 psi to 10,000 psi
Initial pressure accuracy	+-0.015% (1.5 psi at full scale)
Pressure resolution	0.0001 psi
Pressure drift stability	2.0 psi per year at full scale
Calibrated working temperature range	77°F to 302°F (25°C to 150°C)
Initial temperature accuracy	0.27°F (0.15°C)
Temperature resolution	0.0001°F
Temperature drift stability	0.018°F (<0.01°C)
Max temperature	302°F

Note: Specifications from the *Baker Hughes SureSENS QPT ELITE Pressure/Temperature Gauge* are provided as an example of typical specifications from a vendor. A similar product may be used.

Table 11: Wellhead Pressure/Temperature Gauge Vendor Specifications

Parameter	Value
Calibrated working pressure range	0-5,000 psi
Initial pressure accuracy	±0.03% FS
Pressure resolution	0.0003% FS
Pressure drift stability	< 3.0 psi
Calibrated working temperature range	-4ºF to 158ºF
Initial temperature accuracy	±0.09 ºF (0.5ºC)
Temperature resolution	0.02 ºF (0.01 ºC)
Max temperature	158ºF

Note: Specifications from a *PPS PPS31 Wellhead Pressure Logger* are provided as an example of typical specifications from a vendor. A similar product may be used.

Table 12: Leak Detection – Handheld Leak Detection Device

Parameter	Value
Calibrated working detection range	0 – 10,000 ppm CO_2
Accuracy	±5% of reading or ±2% of full scale
Measurement resolution	20 ppm

Table 13: Mass Flow Rate Field Gauge – CO_2 Mass Flow Rate Vendor Specifications

Parameter	Value
Calibrated working flow rate range	547.95-3,561.64 mt/d
Mass flow rate accuracy	±0.10% of rate (liquid), ±0.35% of rate (gas)
Mass flow rate repeatability	±0.10% of rate (liquid), ±0.20% of rate (gas)
Mass flow rate drift stability	To be determined

Note: Specifications from an *Emerson Coriolis Mass Flow Meter* are provided as an example of typical specifications from a vendor. A similar product may be used.

A.5. Special Training/Certifications

A.5.a Specialized Training and Certifications

All sampling equipment and wireline logging tools will be operated by trained, qualified, and, where required, certified personnel according to the service company which provides the equipment. Subsequent data will be processed and analyzed by technically skilled personnel according to industry standards. Groundwater sampling and laboratory chemical analysis will be evaluated by EPA certified laboratories that employ qualified and experienced personnel who understand and regularly follow environmental sampling/chemical analysis standard operating procedures and quality control protocols. Longleaf CCS, LLC will provide relevant certifications for all vendor/subcontractor staff upon request.

A.5.b/c Training Provider and Responsibility

Longleaf CCS, LLC or the designated subcontractor for the data collection activities will provide necessary training for personnel.

A.6. Documentation and Records

The Longleaf CCS Hub monitoring program is broken down into several focus areas:

- *Operational Monitoring:* CO_2 stream analysis, CO_2 injection rate and pressure, annular pressure/volume, corrosion monitoring, wellhead/valve leak detection.
- *Hydrogeologic Testing:* Pressure falloff tests.
- *Mechanical Integrity Testing:* DTS and PNC logging.
- *Direct Plume Monitoring:* Downhole and surface pressure/temperature gauges
- *Indirect Plume Subsurface Monitoring:* PNC logging, DAS, VSPs, DTS.
- *Above-Zone Monitoring:* DTS, downhole pressure/temperature gauges, formation fluid sampling.
- *Deep and Shallow USDW Monitoring:* Fluid sampling.

Each monitoring focus area produces different types of data and has distinct data-management needs (input, storage, processing, manipulation, querying, access/output). In order to efficiently store and utilize this array of data, several databases under individual tasks (i.e., pressure monitoring) will be generated and maintained, depending on their compatibility with an overarching distributed data-management system. To the best degree possible, these individual databases will be linked to a centralized database and file archive system. Monitoring data will be collected under the appropriate quality assurance protocols (e.g., compliance related data will have higher QA protocols than non-compliance related data). These various data sets will be acquired and manipulated into many different file-formats and data forms (hard copy, electronic image files, physical samples, etc.). Each data type will require different data-management protocols and storage/management tools which may vary from simple file management to relational databases to geographic information systems.

Technical experts will screen, validate, and/or pre-process raw data to produce "interpretation-ready" or interpreted data sets. Data with different levels of quality assurance differentiations (e.g., legacy data vs compliance-driven data) and at different levels of processing/verification will be managed separately.

A.6.a Report Format and Package Information

Longleaf CCS, LLC will provide the UIC Program Director with semi-annual reports containing all relevant project data and testing and monitoring information for the reporting period in compliance with 40 CFR 146.91(a). Refer to Section K of the *Testing and Monitoring Plan* for further detail on the timing and content of reporting for specific events and operations.

A.6.b Other Project Documents, Records, and Electronic Files

Other documents, records, and electronic files such as well logs, test results, plugging reports, or other data will be stored and maintained for 10 years post site closure and provided at the request of the UIC Program Director.

A.6.c/d Data Storage and Duration

Pursuant to 40 CFR 146.91(f)(3), any monitoring data collected through implementation of the *Testing and Monitoring Plan* will be retained for at least 10 years after it is collected. All site characterization data will be retained throughout the life of the geologic sequestration project and for at least 10 years following site closure. See Section K.4 of the *Testing and Monitoring Plan* for further information on data and document retention.

A.6.e *QASP* Distribution Responsibility

A representative from Longleaf CCS, LLC will be designated as the responsible party for ensuring that all those on the distribution list will receive the most current copy of the approved *QASP*.

B. Data Generation and Acquisition

B.1. Sampling Process Design

This section describes the monitoring network that will be used to support collection of the various characterization and monitoring measurements needed to ensure safe and nominal CO_2 injection operations, track the development of the CO_2 plume and elevated pressure front, and identify/quantify any potential leakage of CO_2. Based on the current conceptual understanding of the Longleaf CCS Hub geology, this strategy was developed to ensure safe, long-term containment of CO_2 within the injection interval and non-endangerment of USDWs.

B.1.a Design Strategy

CO_2 Stream Monitoring Strategy

The objective of repeatedly analyzing the CO_2 stream is to evaluate the potential interactions of CO_2 and/or other constituents of the injectate with formation solids and fluids. This analysis can also identify (or rule out) potential interactions with well materials. Establishing the chemical composition of the injectate also supports regulatory determinations under the Resource Conservation and Recovery Act (RCRA)[16] and the Comprehensive Environmental Response, Compensation, and Liability Act (CERCLA)[17]. Additionally, monitoring the chemical and physical characteristics of the CO_2 may help distinguish the injectate from the native fluids and gases if unintended leakage from the storage reservoir occurred.

[16] Resource Conservation and Recovery Act (RCRA), 42 U.S.C. 6901 et seq. (1976)
[17] Comprehensive Environmental Response, Compensation, and Liability Act, (CERCLA) 42 U.S.C. 9601 et seq. (1980).

Longleaf CCS, LLC expects multiple sources of CO_2 from the Mobile, Alabama region, with additional sources to be added throughout the life of the project. Each source will have a different gas stream composition, and the composition of the final injected gas stream will change slightly depending on which sources are operational. In order to detect any significant changes in the physical or chemical properties of the CO_2 stream that may result in a deviation from the permitted specifications, Longleaf CCS, LLC will analyze the CO_2 stream continuously with a gas chromatograph at the master meter located at the Injection Well LL#2 wellpad. Additionally, physical samples will be taken quarterly to be tested for hydrogen sulfide and total sulfur content (See Section B of the *Testing and Monitoring Plan* for more details).

Corrosion Monitoring Strategy

Corrosion coupon analyses will be conducted quarterly to aid in ensuring the mechanical integrity of the equipment in contact with the CO_2. Coupons shall be sent out quarterly for analysis, which will be conducted in accordance with the NACE RP0775-2018[18] standard to determine and document corrosion wear rates based on mass loss.

Shallow Groundwater Monitoring Strategy

Ten monitoring wells will be constructed for shallow groundwater monitoring at the Longleaf CCS Hub. These wells will be installed and screened in a near-surface freshwater source to monitor the geochemistry of groundwater commonly accessed by private water wells in the area. The wells were selected to give a representative spatial distribution around the planned CO_2 injection wells and modeled plume development.

Above-Zone and Deep Groundwater Monitoring Strategy

Two above-zone monitoring wells will be completed in the Upper Tuscaloosa Formation and four deep USDW monitoring wells will be completed in the Chickasawhay Formation (lowest most USDW). The above-zone monitoring wells will serve to detect any early leakage above the confining zone, and the deep USDW monitoring wells will monitor the formation fluid geochemistry of the lowest most USDW. In addition to baseline

[18] The National Association of Corrosion Engineers (NACE) Standard RP0775, (2018). *Preparation, Installation, Analysis, And Interpretation of Corrosion Coupons In Oilfield Operations*, Houston, TX. ISBN 1-57590-086-6.

sample collection and analysis prior to the start of injection, pressurized fluid samples will be collected from these six monitoring wells during the injection phase. Mechanical Integrity Testing and downhole temperature monitoring at the injection wells will also provide data to ensure the mechanical integrity of the well is maintained. With the planned sampling and monitoring frequencies, baseline conditions will be documented, natural variability in conditions will be characterized, unintended brine or CO_2 leakage will be detected, and sufficient data will be collected to demonstrate that the effects of CO_2 injection are limited to the intended Paluxy Formation storage reservoir.

Parameters will include selected constituents that: (1) have primary and secondary EPA drinking water maximum contaminant levels, (2) are the most responsive to interaction with CO_2 or brine, (3) are needed for quality control, and (4) may be needed for geochemical modeling. After a sufficient baseline is established, monitoring scope may shift to a subset of indicator parameters that are (1) the most responsive to interaction with CO_2 or brine and (2) are needed for quality control to accurately test for and monitor the presence (or lack thereof) of CO_2 migration. Implementation of a reduced set of parameters would be done in consultation with the UIC Program Director. During any period where a reduced set of analytes is used, if statistically significant trends are observed that are the result of unintended CO_2 or brine migration, the analytical list would be expanded to the full set of monitoring parameters. All groundwater and formation fluid samples will be analyzed using a laboratory meeting the requirements under the EPA Environmental Laboratory Accreditation Program. The full list of analytical parameters and selected methods is provided in **Table 3.**

Direct CO_2 Plume and Pressure Front Monitoring Strategy

Downhole pressure/temperature gauges will be used in all deep monitoring and injection wells to directly monitor the formation pressure and temperature of the injection reservoir (Paluxy Formation) and above-zone interval (Upper Tuscaloosa Formation). Downhole pressure/temperature gauges will continuously monitor for any changes in injection pressure/temperature or in-zone and above-zone pressure/temperature.

Indirect CO_2 Plume and Pressure Front Monitoring Strategy

Several technologies will be deployed within the injection and deep monitoring wells to indirectly monitor the presence/absence of the CO_2 plume and elevated pressure front. A fiberoptic line with DTS and DAS capabilities will be run along the outside of the long-string casing through the Tuscaloosa Marine Shale to continuously record temperature and acoustic variations. External mechanical integrity at all deep wells (injection, in-zone, and above-zone monitoring wells) will be monitored continuously using DTS. PNC logging techniques will be utilized to verify external MIT for each injection and deep monitoring well by detecting the presence or absence of CO_2 in critical formations. PNC logging will also serve to track the CO_2 plume progression in in-zone monitoring wells.

B.1.b Sampling Site Contingency

All testing and monitoring techniques will take place on private property of the project stakeholders, and Longleaf CCS, LLC will have leased all well pad locations. No problems of site inaccessibility are anticipated. If inclement weather makes site access difficult, sampling schedules will be revised and alternative dates may be selected that would still meet permit-related conditions.

B.1.c Critical/Informational Data

Detailed field and laboratory documentation will be recorded on field and laboratory forms and notebooks during groundwater sampling and analytical efforts. Critical information to be documented includes time and date of activity, person(s) performing activity, location of activity, instrument calibration data, and field parameter values. For laboratory analyses, many critical data are generated during the analysis process and provided to end users in digital and printed formats. Noncritical data may include appearance and odor of the sample, issues with well or sampling equipment, and weather conditions.

B.1.d Sources of Variability

Potential sources of variability relating to testing and monitoring activities include:

- Natural variation in formation pressure/temperature, fluid quality, and seismic activity.
- Variation in formation pressure/temperature, fluid quality, and seismic activity associated with nominal project operations.
- Changes in recharge due to precipitation (seasons).
- Changes in instrument calibration during sampling or analytical activity.
- Different personnel collecting or analyzing samples.
- Variation in environmental conditions during field sampling.
- Changes in analytical data quality during life of the project.
- Data entry errors.

Variability related to testing and monitoring activities may be eliminated or mitigated through the following methods:

- Gathering sufficient baseline data to observe natural variation in monitoring parameters.
- Evaluating data in a timely manner after collection to observe anomalies that can be addressed by resampling or reanalyzing.
- Conducting statistical analysis of data to determine whether variability is natural/expected variation or unexpected variation.
- Maintaining weather-related data from onsite sources or from nearby locations (such as a local airport).
- Verifying instrument calibration before, during, and after sampling and analysis.
- Ensuring that staff are fully trained and certified if appropriate.
- Performing laboratory quality assurance checks using third party reference materials, and/or blind/replicate sample checks.
- Utilizing a systematic review process of data that may include sample-specific data quality checks.

B.2. Sampling Methods

B.2.a/b Sampling Standard Operating Procedures

The primary groundwater sampling method will be a low-flow sampling method consistent with ASTM D6452-99[19] or Puls and Barcelona[20]. If a flow-through cell is not used, field parameters will be measured in grab samples. Prior to sampling, wells will be purged to ensure samples are representative of formation fluids. Before any purging or sampling activities begin, static water levels will be measured using an electronic water level indicator. Each groundwater monitoring well will contain a dedicated pump (e.g., bladder pumps) to minimize potential cross contamination between wells. Given sufficient flow rates and volumes, field parameters such as groundwater pH, temperature, specific conductance, and dissolved oxygen will be monitored in the field using portable probes and a flow-through cell consistent with standard methods[21]. Field chemistry probes will be calibrated at the beginning of each sampling day according to equipment manufacturer procedures using standard reference solutions. When a flow-through cell is used, field parameters will be continuously monitored and will be considered stable when three successive measurements made three minutes apart meet the criteria listed in **Table 14.**

Table 14: Stabilization Criteria of Water Quality Parameters During Shallow Well Purging

Field Parameter	Stabilization Criteria
pH, temperature, specific conductance, dissolved oxygen, turbidity	*parameter measurement until ±10% value stabilization

*Exact parameter stabilization threshold will depend on which purge method is selected from ASTM DX

Groundwater samples will be collected after field parameters have stabilized. Flow-through filter cartridges (0.45 µm) will be utilized as required and consistent with ASTM D6564-00[22]. Prior to sample collection, filters will be purged with a minimum of 100 mL of

[19] ASTM, 2005, Method D6452-99 (reapproved 2005), *Standard Guide for Purging Methods for Wells Used for Ground-Water Quality Investigations*, ASTM International, 100 Barr Harbor Drive, West Conshohocken, PA

[20] Puls, R W, and Barcelona, M J. *Ground water issue: Low-flow (minimal drawdown) ground-water sampling procedures*. United States: N. p., 1996. Web.

[21] APHA, 2005, Standard methods for the examination of water and wastewater (21st edition), American Public Health Association, Washington, DC.

[22] ASTM, 2017, Method D6564-00, *Standard Guide for Field Filtration of Ground-Water Samples*, ASTM International, 100 Barr Harbor Drive, West Conshohocken, PA.

well water (or more if required by the filter manufacturer). For alkalinity and total CO_2 samples, efforts will be made to minimize exposure to the atmosphere during filtration, collection in sample containers, and analysis.

B.2.c Continuous Monitoring

Injection Process Monitoring

Data related to the operational process (injection rate and volume and annular pressure and volume) will be continuously monitored with pressure/temperature gauges, flow meters, and the annulus monitoring system, all of which will be linked to the surface control system controlled by Longleaf CCS, LLC. This operational data will ensure that injection is operating safely, efficiently, as expected, and not posing a risk to any USDWs. Additionally, continuously monitored operational parameters will feed into reservoir and computational models to validate that the CO_2 plume and pressure front are behaving as expected.

DTS

DTS technology will continuously collect temperature data along a fiberoptic line installed along the outside of the long-string casing. The DTS line will collect temperature data along the long-string casing every 10 minutes to verify mechanical integrity and monitor the presence or absence of the CO_2 plume.

DAS

DAS technology will continuously collect acoustic data along a fiberoptic line installed along the outside of the long-string casing. Additionally, DAS will be utilized during VSPs to measure the arrival times of seismic waves in the subsurface to monitor the footprint of the CO_2 plume.

Pressure/Temperature Gauges

Downhole pressure/temperature gauges will be deployed within all deep wells to continuously measure pressure/temperature variations within the Paluxy Formation injection interval and Upper Tuscaloosa Formation above-zone monitoring interval.

Downhole pressure/temperature gauges will directly monitor the presence or absence of the CO_2 plume and elevated pressure front.

B.2.d Sample Homogenization, Composition, Filtration

Described in Section B.2.b.

B.2.e Sample Containers and Volumes

All samples will be collected in new containers using industry accepted standards and practices. Container type and size for each sample type are listed in **Table 15** and **Table 16**.

Table 15: Summary of Sample Containers, Preservation Treatments, and Holding Times for CO_2 Gas Stream Analysis

Sample	Volume/Container Material	Preservation Technique	Sample Holding time (max)
CO_2 gas stream	(2) 2L MLB Polybags (1) 75 cc Mini Cylinder	Sample Storage Cabinets	5 Business Days

Table 16: Summary of Anticipated Sample Containers, Preservation Treatments, and Holding Times for Groundwater Samples

Target Parameters	Volume/Container Material	Preservation Technique	Sample Holding Time
Cations: Ca, Fe, K, Mg, Na, Si, Al, Ba, Mn, As, Cd, Cr, Cu, Pb, Sb Se, Tl	250 ml/HDPE	Filtered, nitric acid, cool 4°C	60 days
Dissolved CO_2	2 × 60 ml/HDPE	Filtered, cool 4°C	14 days
Isotopes: 3H, δD, δ18O, δ34S, and δ13C	2 × 60 ml/HDPE	Filtered, cool 4°C	4 weeks
Isotopes: δ34S	250 ml/HDPE	Filtered, cool 4°C	4 weeks
Isotopes: δD, δ18O, δ13C	60 ml/HDPE	Filtered, cool 4°C	4 weeks
Alkalinity, anions (Br, Cl, F, NO_3, SO_4)	500 ml/HDPE	Filtered, cool 4°C	45 days
Field Confirmation: Temperature, dissolved oxygen, specific conductance, pH	200 ml/glass jar	None	< 1 hour
Field Confirmation: Density	60 ml/HDPE	Filtered	< 1 hour

B.2.f Sample Preservation

Sample preservation methods are outlined in **Table 15** and **Table 16**.

B.2.g Cleaning/Decontamination of Sampling Equipment

Pumps will be installed in each groundwater monitoring well in order to mitigate potential cross contamination among wells. Each installed pump will remain in the well for the duration of the project except for maintenance or replacement. The pumps will be cleaned on the outside before installation with a non-phosphate detergent. The pump will then be rinsed appropriately with deionized water. At least 1.0 L of deionized water will be cycled through the pump and tubing. Individual prepared pumps and tubing will be placed in clean containers for transport to the field for installation. All sampling glassware (such as pipettes, beakers, filter holders, etc.) will be cleaned using tap water and then washed in a dilute nitric acid solution before being thoroughly rinsed with deionized water prior to use.

B.2.h Support Facilities and Tools

The following tools may be needed to sample groundwater: generator, vacuum pump, compressor, multi-electrode water quality sonde, and various meters to take analytical measurements such as pH and electrical conductance. Analytical field activities may take place in field vehicles and/or portable onsite trailers. Well gauges used for verification will be handled using industry standard best practices and procedures recommended from the vendor.

Coupons consisting of material that will directly contact the CO_2 stream will be placed within a flowline. Each sample will be attached to an individual holder and inserted in a flowthrough pipe arrangement, exposing the samples to the CO_2 stream and allowing access for removal and testing. The flowthrough pipe arrangement will be located at the well location downstream of all process compression, dehydration, and pumping equipment. A parallel stream of high-pressure CO_2 will be routed from the flowline through the corrosion monitoring system. This loop will operate while injection is occurring, providing representative exposure of the samples to the CO_2 composition, temperature, and pressures that will be seen at the wellhead and injection tubing. Injection will be able to continue while samples are removed for testing.

B.2.i Corrective Action, Personnel, and Documentation

Properly testing equipment and implementing corrective actions on broken or malfunctioning field equipment will be the responsibility of field personnel. If corrective action is not possible in the field, then equipment will be sent back to the manufacturer or qualified technician to be repaired, serviced, or replaced. Substantial corrective actions that may impact analytical results will be documented in field notes. In the event that defective equipment will cause disruptions to the sampling schedule, Longleaf CCS, LLC will contact the UIC Program Director.

B.3. Sample Handling and Custody

Sample handling and hold times will be congruent with US EPA (1974)[23], APHA (2005)[24], Wood (1976)[25], and ASTM Method D6517-00 (2005)[26]. Samples will be kept at their preservation temperature and sent to the selected laboratory within 24 hours of collection. Analysis of the samples will be completed within the holding time specified in **Table 16**. If alternative sampling methods become necessary, these methods will be discussed with the UIC Program Director prior to sampling.

B.3.a Maximum Hold Time/Time Before Retrieval

See **Table 15** and **Table 16**.

B.3.b Sample Transportation

Samples will be transported in coolers with ice maintained to approximately 4 degrees Celsius and sent to approved laboratory within 24 hours of sampling.

[23] U.S. Environmental Protection Agency (US EPA), 1974, Methods for chemical analysis of water and wastes, US EPA Cincinnati, OH, EPa-625-/6-74-003a.
[24] APHA, 2005, Standard methods for the examination of water and wastewater (21st edition), American Public Health Association, Washington, DC.
[25] Wood, W.W., 1976, Guidelines for collection and field analysis of groundwater samples for selected unstable constituents, In U.S. Geological Survey, Techniques for Water Resources Investigations, Chapter D-2, 24 p.
[26] ASTM, 2005, Method D6517-00 (reapproved 2005), Standard guide for field preservation of ground-water samples, ASTM International, 100 Barr Harbor Drive, West Conshohocken, PA.

B.3.c Sampling Documentation

Sampling personnel will compile field documentation for all groundwater samples collected. Field notes will be archived.

B.3.d Sample Identification

Each groundwater sample container will have a label with the following information: project name/number, sample date and location, sample ID number, fresh or brine water, volume taken, analyte, filtration used (if applicable), and preservative used (if any).

B.3.e. Sample Chain-of-Custody.

A standardized form will be used to document groundwater sample chain-of-custody. Copies of this form will be provided to laboratory personnel upon delivery of groundwater samples for analysis. These forms will be archived for future reference.

B.4. Analytical Methods

B.4.a Analytical Standard Operating Procedures

Analytical standard operating procedures are referenced in **Table 3** through **Table 7**. Other laboratory specific standard operating procedures utilized by the laboratory will be determined after a contract laboratory has been selected. Upon request, Longleaf CCS, LLC will provide the UIC Program Director with all laboratory standard operating procedures developed for the specific parameter using the appropriate standard method. Each laboratory technician conducting the analysis on the samples will be trained on the standard operating procedure developed for each standard method.

B.4.b Equipment/Instrumentation Needed

Equipment and instrumentation are specified in the individual analytical methods referenced in **Table 3** through **Table 7.**

B.4.c Method Performance Criteria

Nonstandard method performance criteria are not anticipated for this project.

B.4.d Analytical Failure

Each laboratory conducting the analyses in **Table 3** through **Table 7** will be responsible for appropriately addressing analytical failure according to their individual standard operating procedures.

B.4.e Sample Disposal

Each laboratory conducting the analyses in **Table 3** through **Table 7** will be responsible for appropriate sample disposal according to their individual standard operating procedures.

B.4.f Laboratory Turnaround

Laboratory turnaround will vary by laboratory, but generally turnaround of verified analytical results within two months will be suitable for project needs.

B.4.g Method Validation for Nonstandard Methods

Nonstandard methods are not anticipated for this project. If nonstandard methods are needed or proposed in the future, the UIC Program Director will be consulted on appropriate actions to be taken.

B.5. Quality Control

B.5.a QC activities

Blanks

Field blanks will be utilized for both the shallow and deep groundwater sampling to identify potential contamination due to the collection and transportation processes. Field blanks will be collected and analyzed for the inorganic analytes listed in **Table 3** at a frequency of 10% or more. The field and transportation conditions for field blanks will be the same as those of the groundwater samples.

Duplicates

During each round of shallow groundwater sampling, a second groundwater sample is collected from one well, selected based on a rotating schedule. These duplicate samples are collected from the same source and at the same time as the original sample in a different, yet identical, sample container. Duplicate samples are processed with all other samples and are used to determine sample heterogeneity and analytical precision.

B.5.b Exceeding Control Limits

If the sample analytical results exceed control limits (i.e., ion balances > ±10%), further examination of the analytical results will be done by evaluating the ratio of the measured total dissolved solids (TDS) to the calculated TDS (i.e., mass balance) per APHA method. The method indicates which ion analyses should be considered suspect based on the mass balance ratio. Suspect ion analyses are then reviewed in the context of historical data and interlaboratory results, if available. Suspect ion analyses are then brought to the attention of the analytical laboratory for confirmation and/or reanalysis. The ion balance is recalculated, and if the error is still not resolved, suspect data are identified and may be given less importance in data interpretations.

B.5.c Calculating Applicable QC Statistics

Charge Balance

The groundwater sample analytical results are evaluated to determine correctness of analyses based on anion-cation charge balance calculation. All potable waters are electrically neutral; thus, the chemical analyses should produce equally negative and positive ionic activity. The anion-cation charge balance will be calculated using the formula:

$$\%\, difference = 100 * \frac{\sum cations - \sum anions}{\sum cations + \sum anions}$$

where the sums of the ions are represented in milliequivalents (meq) per liter, and the criteria for acceptable charge balance is ±10%.

Mass Balance

The ratio of the measured TDS to the calculated TDS will be calculated in instances where the charge balance acceptance criteria are exceeded using the formula:

$$1.0 <* \frac{measured\ TDS}{calculated\ TDS} < 1.2$$

with anticipated values between 1.0 and 1.2.

Outliers

A determination of one or more statistical outliers is essential prior to the statistical evaluation of groundwater. This project will use the EPA's Unified Guidance (March 2009)[27] as a basis for selection of recommended statistical methods to identify outliers in groundwater chemistry data sets as appropriate. These techniques include Probability Plots, Box Plots, Dixon's test, and Rosner's test. The EPA-1989[28] outlier test may also be used as another screening tool to identify potential outliers.

B.6. Instrument/Equipment Testing, Inspection, and Maintenance

Logging tool equipment will be maintained as per wireline industry best practices. Pressure/temperature gauges will be maintained to manufacturer standards. For groundwater sampling, field equipment will be maintained, factory serviced, and factory calibrated per manufacturer's recommendations. Spare parts that may be needed during sampling will be included in supplies on-hand during field sampling. For laboratory equipment, all testing, inspection, and maintenance will be the responsibility of the analytical laboratory per standard practice or method-specific protocol.

B.7. Instrument/Equipment Calibration and Frequency

B.7.a Calibration and Frequency of Calibration

Pressure/temperature gauge calibration information is located in **Table 10** and **Table 11.** All field and downhole gauges will be calibrated prior to use by the equipment supplier. Gauges will be recalibrated as needed based on results of inspection, or after any repairs or maintenance. Logging tool calibration will be at the discretion of the service company providing the equipment, following standard industry practices. Calibration frequency will be determined by standard industry practices. CO_2 flow meters will be

[27] U.S. Environmental Protection Agency (US EPA), 2009, Statistical analysis of groundwater monitoring data at RCRA facilities—Unified Guidance, US EPA, Office of Solid Waste, Washington, DC.
[28] U.S. Environmental Protection Agency (US EPA) 2009, Data Quality Assessment: Statistical Methods for Practitioners, US EPA Cincinnati, OH, EPA-QA/G-9S

calibrated using industry standards and at a frequency recommended by the manufacturer.

For groundwater sampling, portable field meters or multiprobe sondes used to determine field parameters (e.g., pH, temperature, specific conductance, dissolved oxygen) will be calibrated according to manufacturer recommendations and equipment manuals (Hach, 2006)[29] before sample collection begins. Recalibration is performed if any components yield atypical values or fail to stabilize during sampling.

For CO_2 stream sampling, the gas chromatograph will be calibrated based on the manufacturer's guidance.

B.7.b Calibration Methodology

Calibration of the orifice flow meters will be carried out using the carrier gas to validate the characteristics of the approved CO_2 composition using methods described in **Table 7**. Logging tool and all field and downhole gauge calibration methodology will follow standard industry practices recommended by the respective manufacturers.

For groundwater sampling, standards used for calibration typically require a pH of 7 and 10, a potassium chloride solution with 1,413 microseimens per centimeter (µS/cm) at 25°C for specific conductance, and a 100% dissolved oxygen solution. Calibration of pH meters will be performed per manufacturer's specifications using a 2-point calibration bounding the range of the sample. For coulometry, sodium carbonate standards (typically with a concentration of 4,000 mg CO_2/L) are routinely analyzed to evaluate instrument.

B.7.c Calibration Resolution and Documentation

Logging tool calibration resolution and documentation will follow standard industry practices. Groundwater sampling equipment calibration occurs regularly, and values are recorded in sampling records, with any errors in calibration noted. For parameters where calibration is not acceptable, redundant equipment may be used so loss of data is minimized.

[29] Hach Company, February 2006, Hydrolab DS5X, DS5, and MS5 Water Quality Multiprobes User Manual, Hach Co., 73 p.

B.8. Inspection/Acceptance for Supplies and Consumables

B.8.a/b Supplies, Consumables, and Responsibilities

Individual vendors and subcontractors selected and approved by Longleaf CCS, LLC will be responsible for ensuring that all supplies and consumables for field and laboratory operations are inspected and acceptable for data collection activities. Procurement of supplies and consumables related to groundwater analyses will be the responsibility of the laboratory conducting water analyses in accordance with the established standard methodologies and operating procedures.

B.9. Nondirect Measurements

B.9.a Data Sources

Plume development will also be monitored via DTS, DAS 3D-VSP, and PNC logs. PNC logs detect CO_2 concentration surrounding the wellbore, and repeat logging runs will be compared to the baseline conducted before injection operations begin. DTS monitors variations in temperature along the wellbore at a high resolution, measured approximately every 10 minutes. DAS measures strain caused by acoustic waves passing through/near the fiberoptic cable installed on the outside of the long string casing and can act as a downhole VSP geophone.

B.9.b Relevance to Project

Time-lapse VSPs and scheduled PNC logging will be used to track CO_2 plume movement. After initial baseline testing is conducted prior to injection, processing and comparison of subsequent surveys will allow Longleaf CCS, LLC to monitor the extent of the plume, ensuring that the plume is contained and behaving as expected. Numerical modeling will be updated with new seismic, pressure, and saturation data throughout the project to best characterize the CO_2 plume growth and movement over time.

B.9.c Acceptance Criteria

The collection of seismic data will follow standard industry practices to ensure accuracy in the resulting data. Similar ground conditions, seismic shot points located within acceptable limits, carefully inspected and operational geophones, and uniform seismic input signal will be used for each survey to ensure repeatability.

Gauges and other logging equipment used to collect non-direct measurements will be checked periodically and maintained according to manufacturer recommendations for equipment care and operation, to ensure the accuracy of readings as they are incorporated into the model.

B.9.d Resources/Facilities Needed

Longleaf CCS, LLC will subcontract all necessary resources and facilities for the seismic monitoring, logging, in-zone pressure monitoring, and groundwater sampling.

B.9.e Validity Limits and Operating Conditions

Intraorganizational verification by trained and experienced personnel will ensure that all seismic surveys and numerical modeling are conducted according to industry standards.

B.10. Data Management

B.10.a Data Management Scheme

Longleaf CCS, LLC or a designated contractor will maintain the required project data as described in Section K.4 of the *Testing and Monitoring Plan*. Data will be backed up on secure servers.

B.10.b Recordkeeping and Tracking Practices

All records of gathered data will be securely held and properly labeled for auditing purposes.

B.10.c Data Handling Equipment/Procedures

All equipment used to store data will be properly maintained and operated according to proper industry techniques. Longleaf CCS, LLC will ensure that all necessary supervisory control and data acquisition (SCADA) systems and vendor data acquisition systems will interface with one another and that all subsequent data will be held on a secure server.

Meter data will be captured via the flow computer.

B.10.d Responsibility

The primary Longleaf CCS, LLC project manager will be responsible for ensuring proper data management is maintained during pre-operational testing and the Operations Manager for the injection and post-injection periods.

B.10.e Data Archival and Retrieval

All data will be held and maintained by Longleaf CCS, LLC as described in Section K.4 of the *Testing and Monitoring Plan*. Data will be backed up on secure servers to be accessed by project personnel as required.

B.10.f Hardware and Software Configurations

All Longleaf CCS, LLC and vendor hardware and software configurations will interface appropriately.

B.10.g Checklists and Forms

Checklists and forms will be generated and completed as necessary.

C. Assessment and Oversight

C.1. Assessments and Response Actions

C.1.a Activities to be Conducted

Refer to **Table 1** and **Table 2** for a summary of work to be performed and proposed work schedule. After completion of groundwater sample analysis, the results will be reviewed for quality control criteria as noted in Section B.5 of this *QASP*. If the data fail to meet the established quality criteria, samples will be reanalyzed if still within holding time criteria. If outside of holding time criteria, additional samples may be collected or sample results may be excluded from data evaluations and interpretations. Evaluation for data consistency will be performed according to procedures described in the EPA 2009 Unified Guidance[30].

C.1.b Responsibility for Conducting Assessments

Each organization gathering data will be responsible for conducting their own internal assessments. All stop work orders will be handled internally within each individual organization.

C.1.c Assessment Reporting

All assessment information will be reported to the Longleaf CCS, LLC project manager.

C.1.d Corrective Action

All corrections which may affect a single organization's data collection responsibility shall be addressed, verified, and documented by the individual project managers, and communicated to others as necessary. Corrective actions affecting multiple organizations should be addressed by all members of the project leadership and communicated to other members on the *QASP* distribution list. Integration of information from multiple monitoring sources (operational, in-zone monitoring, above-zone monitoring) may be required to determine whether data and/or measurement method corrections are required, as well as the most effective and cost-efficient action to implement. Longleaf CCS, LLC will coordinate multiorganization assessments and correction efforts as needed.

C.2. Reports to Management

C.2.a/b QA Status Reports

QA status reports are not required unless there are significant adjustments to the methods and procedures listed above. If any testing or monitoring techniques are

[30] U.S. Environmental Protection Agency (US EPA), 2009, Statistical analysis of groundwater monitoring data at RCRA facilities—Unified Guidance, US EPA, Office of Solid Waste, Washington, DC.

changed, this *QASP* will be reviewed and updated appropriately after consultation with the UIC Program Director. The revised *QASP* will be distributed by Longleaf CCS, LLC to the full distribution list noted at the beginning of this document.

D. Data Validation and Usability

D.1. Data Review, Verification, and Validation

D.1.a Criteria for Accepting, Rejecting, or Qualifying Data

Validation of data will include a review of concentration units, sample holding times, and the review of duplicate, blank, and other appropriate QA/QC results. Longleaf CCS, LLC will hold copies of all laboratory analytical test results and/or reports. Analytical results will be reported as described in Section K of the *Testing and Monitoring Plan*. In the periodic reports, groundwater analysis data will be presented in graphical and tabular formats as appropriate to characterize general groundwater quality and identify intrawell variability with time. After sufficient data have been collected, additional methods, such as those described in the EPA 2009 Unified Guidance[31] will be used to evaluate intrawell variations for groundwater constituents, to evaluate if significant changes have occurred that could be the result of CO_2 or brine seepage beyond the intended storage reservoir.

D.2. Verification and Validation Methods

D.2.a Data Verification and Validation Processes

See Sections D.1.a and B.5. of this *QASP.* Appropriate statistical software will be utilized to determine data consistency.

[31] U.S. Environmental Protection Agency (US EPA), 2009, Statistical analysis of groundwater monitoring data at RCRA facilities—Unified Guidance, US EPA, Office of Solid Waste, Washington, DC.

D.2.b Data Verification and Validation Responsibility

Longleaf CCS, LLC or its designated subcontractor will verify and validate groundwater sampling data.

D.2.c Issue Resolution Process and Responsibility

Longleaf CCS, LLC will designate a Site Coordinator, who will oversee the groundwater data handling, management, and assessment process. Staff involved in these processes will consult with the Coordinator to determine actions required to resolve any issues.

D.2.d Checklist, Forms, and Calculations

Checklists and forms will be developed specifically to meet permit requirements. These checklists will largely depend on the parameters that are being tested as well as standard operating procedures of the subcontractors and laboratories that will be gathering the data and conducting the analyses. Longleaf CCS, LLC will provide these forms and checklists to the UIC Program Director upon request. **Table 17** provides an example of the type of information that may be used for data verification of groundwater quality data.

Table 17: Example table of criteria used to evaluate data quality

MVA ID	Anion charge	Cation charge	Charge balance	CB rating	Calculated TDS	Measured TDS	TDS Ratio	TDS Rating
ICCS_10B_01A	14.4	13.60	-2.84	pass	760.50	785	1.0	pass

D.3. Reconciliation with User Requirements

D.3.a Evaluation of Data Uncertainty

Statistical software will be used to determine groundwater data consistency using methods consistent with EPA 2009 Unified Guidance.[32]

D.3.b Data Limitations Reporting

Each vendor or subcontractor's project manager will be responsible for ensuring that data presented by their respective organizations is developed with the appropriate data-use limitations. Longleaf CCS, LLC will ensure that the data-use limitations are known and presented properly.

[32] U.S. Environmental Protection Agency (US EPA), 2009, Statistical analysis of groundwater monitoring data at RCRA facilities—Unified Guidance, US EPA, Office of Solid Waste, Washington, DC.

Longleaf CCS Hub

Longleaf CCS, LLC

Area of Review and Corrective Action Plan

40 CFR 146.84(a), (c)(1)

Facility Information

Facility Name: Longleaf CCS Hub

Facility Contact: Longleaf CCS, LLC
14302 FNB Parkway
Omaha, NE 68154

Well Location: Mobile County, Alabama

LL#1: Latitude: 31.071303° N
Longitude: -88.094703° W
LL#2: Latitude: 31.070774° N
Longitude: -88.074523° W
LL#3: Latitude: 31.0447129° N
Longitude: -88.0736318° W
LL#4: Latitude: 31.0569516° N
Longitude: -88.1047433° W

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List of Acronyms/Abbreviations

AoR	Area of Review
API	American Petroleum Institute
CCS	Carbon Capture and Storage
CO_2	Carbon dioxide
CMG	Computer Modelling Group
DOE	Department of Energy
EPA	Environmental Protection Agency
°F	Degrees Fahrenheit
ft	Feet
ft^3	Cubic feet
ft/yr	Feet per year
GS	Geologic sequestration
GSDT	Geologic Sequestration Data Tool
in	Inches
kg	Kilograms
lb	Pounds
LL	Longleaf
m	Meter
m^3	Cubic meters
mD	Millidarcies
mg/L	Milligrams per liter
MMcf/d	Million standard cubic feet per day
MPa	Megapascals
MSL	Mean sea level
mt	Metric tons
Mt	Million metric tons
mt/d	Metric tons per day
nD	Nanodarcies
psi	Pounds per square inch
psia	Pounds per square inch, absolute
SS	Sub-sea
TD	Total Depth
TDS	Total dissolved solids
UIC	Underground injection control
USDW	Underground source of drinking water
VSP	Vertical seismic profile

A. AoR Delineation Using Computational Modeling

The Area of Review (AoR) is defined as the region where underground sources of drinking water (USDW) may be endangered by CO_2 injection at the Longleaf CCS Hub in Mobile County, Alabama. The AoR is delineated by the lateral and vertical migration of the CO_2 plume and/or the pressure front in the subsurface created by the injection of CO_2. The lateral and vertical extent of the CO_2 plume and the pressure front at the Longleaf CCS Hub were determined from detailed geologic site characterization and rigorous computational modeling. After CO_2 injection commences, operational and monitoring data will be incorporated into additional computational modeling efforts to periodically reevaluate and validate the AoR. [40 CFR 146.84(a)]

A.1 AoR Delineation Class VI Rule Requirements

Sections A.2 through A.4 provide discussion on the data and workflows used to address the federal requirements for AoR delineation provided in 40 CFR 146.84(a) and 40 CFR 146.84(c)(1).

A.2 Introduction to the Longleaf CCS Hub

A.2.a Overview of Longleaf CCS Hub

The Longleaf CCS Hub will inject CO_2 into the sandstones of the Lower Cretaceous-age Paluxy Formation. **Figure 1** provides a regional view of the proposed site for the Longleaf CCS Hub, showing the following:

- Locations of the four proposed injection wells: LL#1, LL#2, LL#3 and LL#4;
- Locations of the proposed in-zone, above-zone, and deep USDW monitoring wells;
- Location of Plant Barry, one of the potential sources of CO_2;

- Locations of the three Citronelle Dome wells used for supporting the characterization of the Longleaf CCS Hub;[1]

- Locations of other previously drilled deep wells used in the analysis of the storage reservoir and its confining unit properties.

Information on the injection, confining, and overlying formations at the Longleaf CCS Hub benefitted greatly from the drilling of three wells at the Citronelle Dome located immediately to the west of the Longleaf CCS Hub including wells D-9-7 #2, D-9-8 #2, and D-9-9 #2 (API# 0109720396). Gamma ray log data from the O.P. Turner #31-4 well (API# 0109720209) and the R.J. Newman 5-7 #1 well (API# 0109720172) were used to create a regional cross section with the Citronelle D-9-8 #2 well. The data from these wells, along with other information, were used to characterize the sub-surface and particularly the Paluxy Formation at the Longleaf CCS Hub.

An extensive set of wireline logs and two sections (barrels) of core were obtained from these wells. Additional data from 80 logs and purchase and interpretation of 38.6 miles of preexisting 2D seismic lines were used to further define the structure, continuity, thickness, and other reservoir properties of the Paluxy Formation and its multiple sealing units at the Longleaf CCS Hub.

[1] Riestenberg, D. “Southeast Regional Carbon Sequestration Partnership (SECARB): Southern States Energy Board, Citronelle”. 10th Annual SECARB Stakeholders’ Briefing Atlanta, GA. Presentation. March 12, 2013.

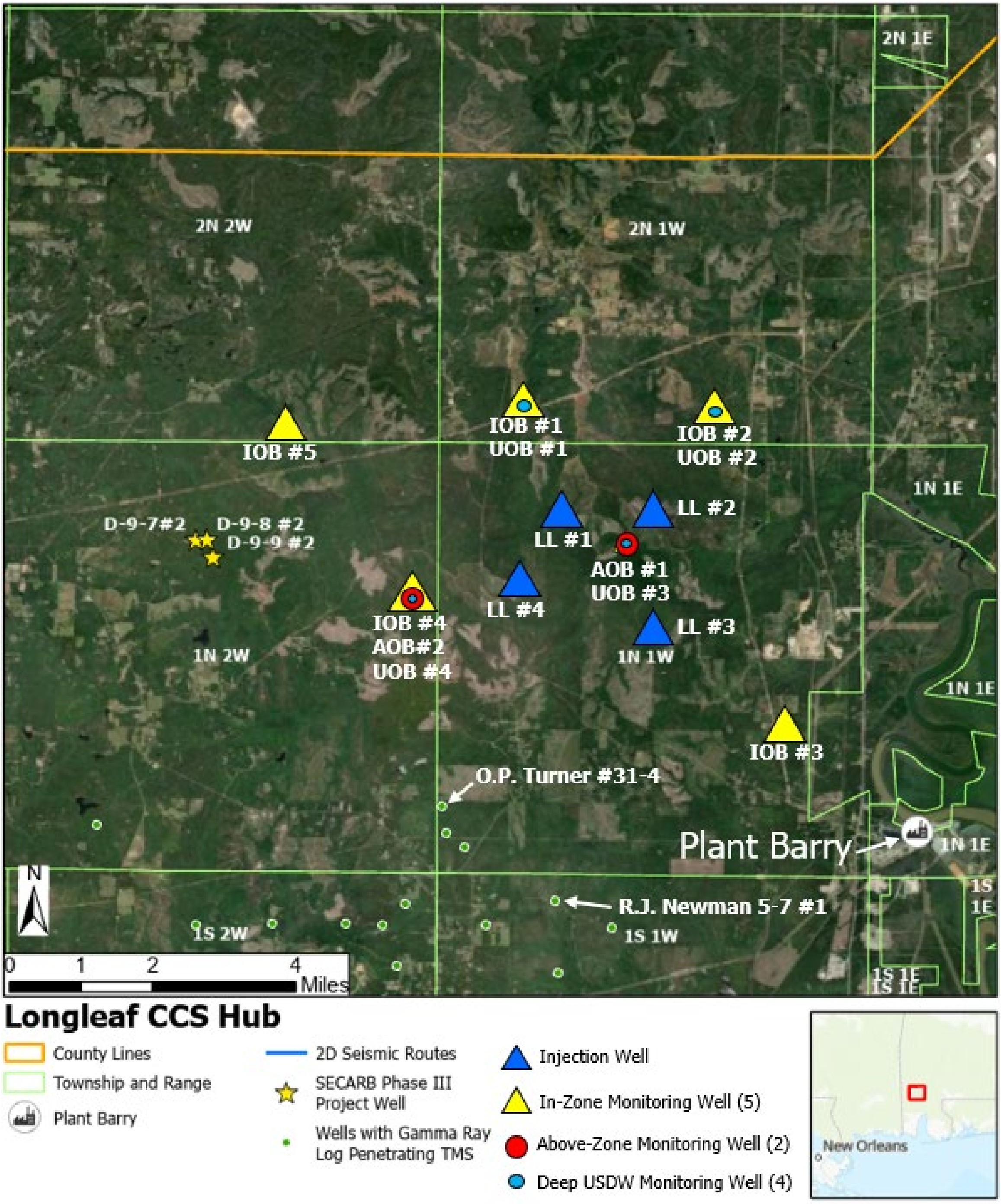

Figure 1: Longleaf CCS Hub Location and Well Map

The presence of faults and other structural features that could act as migration pathways for fluid were reviewed using the recently acquired 2D seismic lines. No faults were found that would have an impact on the proposed injection activity within the Longleaf CCS Hub. **Section B.1.b** of the ***Application Narrative*** discussed the structural setting and 2D seismic profile of the Longleaf CCS Hub in more detail.

A summary description of the geologic setting, lithology, stratigraphy, and hydrology of the Longleaf CCS Hub is provided below. Please refer to the *Application Narrative* for a more detailed geologic description.

A.2.b Summary of the Geologic Setting

The Longleaf CCS Hub is located in the eastern margin of the Mississippi Interior Salt Basin which formed during the Triassic-Jurassic rift-to-drift sequence associated with the opening of the Gulf of Mexico.[2] Structural deformation in the area is primarily from movement of the Jurassic-aged Louann Salt, the basal stratigraphic unit within the basin.[3] The proposed Longleaf CCS Hub and its CO_2 injection wells are located between the two prominent structural features in this area -- the Citronelle Dome to the west and the Mobile Graben to the east, as seen in **Figure 3**. A series of six 2D seismic lines were purchased and interpreted to establish the structural setting of the Longleaf CCS Hub, as discussed in **Section B.1.a** of the ***Application Narrative***.

Figure 2 provides the stratigraphic column for the storage, dissipation and confining units at the Longleaf CCS Hub as well as the local freshwater aquifers and potential USDWs.

[2] Pashin, J. C, McIntyre, M. R., Grace, R. L. B., Hills, D. J., "Southeastern Regional Carbon Sequestration Partnership (SECARB) Phase III, Final Report", Report to Advanced Resources International by Geological Survey of Alabama, Tuscaloosa, September 12, 2008

[3] Pashin, J. C., Kopaska-Merkel, D. C., and Hills, D. J., "Reservoir geology of the Donovan sandstone in Citronelle Field", in Walsh, P. M., ed., Carbon dioxide enhanced oil production from the Citronelle oil field in the Rodessa Formation, South Alabama: Final Scientific/Technical Report, U.S. Department of Energy Award DEFC26-06-NT43029, p. 13-65, 2014

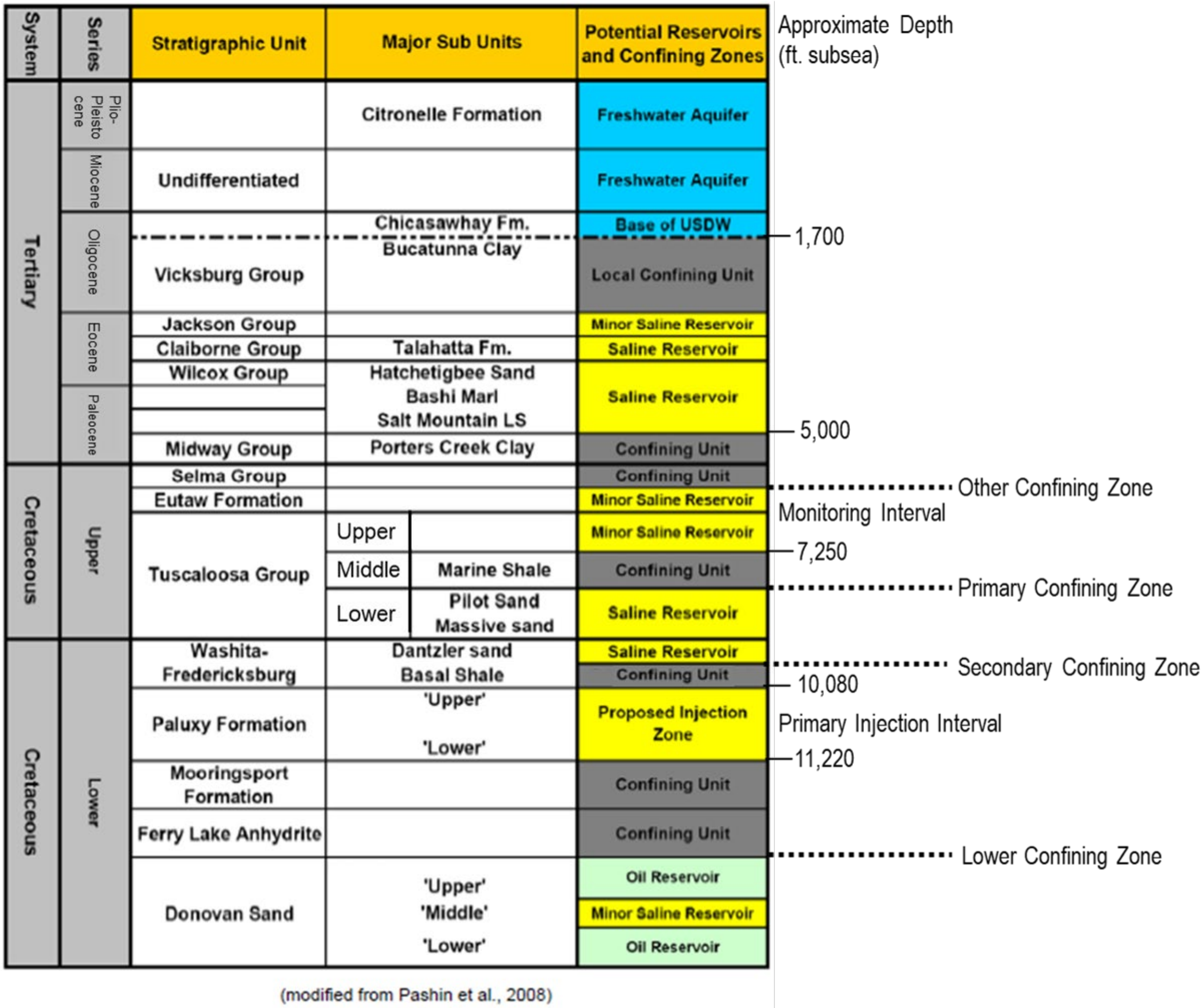

Figure 2: Stratigraphic Units at Proposed Longleaf CCS Hub

The base of the storge interval at the Longleaf CCS Hub is the top of the Lower Cretaceous Mooringsport Formation. The sandstones of the Upper and Lower Cretaceous Paluxy Formation overlying the Mooringsport Formation are the targeted CO_2 injection zone. Above the Paluxy are the Washita-Fredericksburg (Wash-Fred) sandstone and the Massive Sand that could serve as future injection intervals. A series of confining units (seals) are located within the Tuscaloosa interval above the Massive Sand, including the Tuscaloosa Marine Shale, which serve as the primary confining unit for the system.

The depth of the Paluxy Formation near the injection wells at the Longleaf CCS Hub ranges from approximately 10,080 ft at the top to 11,220 ft at the base. Net sand thickness in the Paluxy of about 491 ft is distributed into six main sandstone units. These internal sandstone units are separated by shale and siltstone, which serve as local, vertical flow barriers.

The Paluxy Formation has three regionally significant confining zones— the 150 ft shale unit at the base of the overlying Wash-Fred Formation located above the Paluxy Formation, the 300 ft thick Tuscaloosa Marine Shale that serves as a regional confining zone, and the massive Selma and Midway Group interval that provides an additional 2,000 ft of confinement between the Paluxy and the overlying base of USDW at 1,700 ft.

The USDW protected aquifers within Mobile County include the Pliocene-aged Watercourse aquifer and the Miocene-Pliocene aquifer. The primary source of drinking water in northern Mobile County comes from the lower undifferentiated Miocene series, the base of which is at approximately 900 ft at the Longleaf CCS Hub. The deepest USDW in the Longleaf CCS Hub is the Chickasawhay Limestone at about 1,700 ft.

The USDWs that will be monitored at the Longleaf CCS Hub for leakage of CO_2 or intrusion of saline water include the deepest USDW, the Chickasawhay Limestone, and shallow freshwater aquifers less than 500 ft. below ground surface. The Longleaf CCS Hub will specifically monitor for the following indicators of USDW and groundwater impact from CO_2 leakage or intrusion of saline water: 1) an increase in TDS content if water with higher TDS has migrated into overlying USDW and 2) a reduction in pH of a protected USDW as CO_2 or carbonated brine causes an increase in dissolved carbonate. See **Section B.7** of the ***Application Narrative*** for more on the hydrogeology of the Longleaf CCS Hub.

A.2.c Operational Data

A.2.c.1 Operational Information

The Longleaf CCS Hub plans on injecting 5.0 million metric tons (Mt) of CO_2 per year into the Paluxy Formation for 30 years, totaling 150 Mt. The CO_2 will be injected using four vertical injection wells equipped with 6 5/8 in diameter (outer) injection tubing.

Additional details on the CO_2 injection operation at the Longleaf CCS Hub are presented in **Table 1**.

Table 1: Operating Details

Operating Information	Injection Well 1 (LL#1)	Injection Well 2 (LL#2)	Injection Well 3 (LL#3)	Injection Well 4 (LL#4)
Location (global coordinates) X Y	 31.071303°N -88.094703°W	 31.070774°N -88.074523°W	 31.0447129°N -88.0736318°W	 31.0569516°N -88.1047433°W
No. of perforated intervals	6	6	6	6
Perforated interval (ft MSL)	1: 10,140-10,192 2: 10,226-10,277 3: 10,312-10,637 4: 10,706-10,860 5: 11,086-11,109 6: 11,179-11,225	1: 10,213-10,263 2: 10,297-10,347 3: 10,381-10,700 4: 10,768-10,919 5: 11,146-11,170 6: 11,241-11,289	1: 10,141-10,189 2: 10,220-10,268 3: 10,300-10,603 4: 10,667-10,810 5: 11,049-11,076 6: 11,156-11,209	1: 10,031-10,082 2: 10,115-10,166 3: 10,200-10,521 4: 10,588-10,740 5: 10,960-10,998 6: 11,072-11,121
Injection well tubing diameter (in)	6.625	6.625	6.625	6.625
Planned injection period Start: End:	 2025 2055	 2025 2055	 2025 2055	 2025 2055
Injection duration (years)	30	30	30	30
Injection rate (mt/day)	3,425	3,425	3,425	3,425

It is important to note that this AoR plan serves as an attachment to the UIC Class VI injection well permits associated with the proposed LL#1, LL#2, LL#3, and LL#4 wells.

A.2.c.2 Fracture Pressure and Fracture Gradient

Pressure gauges installed at 9,355 ft (bottom of injection tubing) in the D-9-7 #2 well from the SECARB Phase III injection test at Citronelle Dome demonstrated that sustained pressures of 5,850 psi (0.625 psi/ft) did not result in any observed geomechanical formation impacts. More information on the plans to calculate fracture pressure can be found in the ***Pre-Operational Testing Plan***. To ensure that fracture pressure is not surpassed during the injection of CO_2, a conservative bottomhole pressure limit of 6,930 psia at 11,000 ft (0.63 psi/ft, equal to 90% of the assumed fracture pressure gradient of 0.7 psi/ft) was imposed. For the reservoir simulation, the wells were operated using this constraint, with an additional injection rate constraint of 65 million standard cubic feet per day (MMcf/d) (3,425 metric tons per day [mt/d]), as shown in **Table 2**.

Table 2: Injection Pressure Details

Injection Pressure Details	Injection Well LL#1	Injection Well LL#2	Injection Well LL#3	Injection Well LL#4
Fracture gradient (psi/ft)	0.63	0.63	0.63	0.63
Maximum injection pressure (90% of fracture pressure) (psi)	7,072	7,112	7,062	7,006
Elevation corresponding to maximum injection pressure (ft MSL)	11,225	11,289	11,209	11,121
Elevation at the top of the perforated interval (ft MSL)	10,140	10,213	10,141	10,031
Calculated maximum injection pressure at the top of the perforated interval (psi)	6,388	6,434	6,389	6,319

A.3 Model Development

A.3.a Conceptual Model of the Proposed Injection Site

For the Longleaf CCS Hub, four injection wells are each designed to inject 65 MMcf/d (3,425 mt/d) of CO_2 for 30 years. The sources of CO_2 for the project are the electrical generating station at Plant Barry in Bucks, Alabama and four additional industrial sources. The CO_2 will be supplied by pipeline to the injection site. The injection of CO_2 will be into the Upper and Lower Cretaceous Paluxy sandstone, a saline reservoir occurring at a depth of approximately 10,080 ft at the proposed storage site. The CO_2 injection wells are located in the deeper center of the Longleaf CCS Hub, and it is anticipated that the CO_2 will migrate up-dip towards the east and west.

The Tuscaloosa Marine Shale at 7,250 ft and the basal Wash-Fred shale at approximately 10,000 ft serve as the two key confining units. The geologic model for the Longleaf CCS Hub used in the computational model (*GEM*) to determine the AoR is illustrated on **Figure 3**.

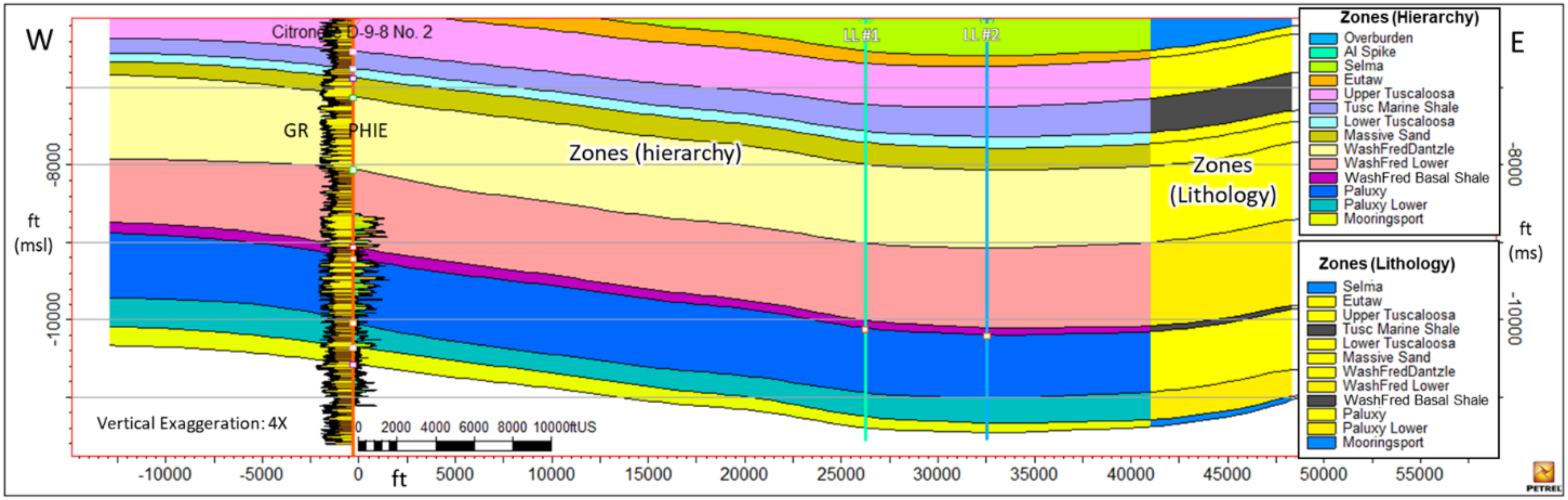

Figure 3: Longleaf CCS Hub Geologic Model

A.3.b Determination of Physical Processes to be Included in the Computational Model

The details of the computational modeling efforts, which satisfy the requirement of 40 CFR 146.84(b), are discussed in this section. Longleaf CCS, LLC will upload in tabular format all relevant datasets used in support of the computational modeling to the EPA's GSDT as they become available.

The Longleaf CCS Hub computational model was constructed by Advanced Resources International, Inc. at the request of Longleaf CCS, LLC. The computational model, drawing on the Computer Modeling Group's (CMG) *GEM* simulator, was developed to model the subsurface injection and flow of CO_2 in the Paluxy formation at the Longleaf CCS Hub in Mobile County, Alabama. *GEM* is a reservoir simulator that uses an equation of state to simulate fully compositional reservoir flow and is used widely by industry for modeling the flow of three-phase, multi-component fluids. This sophisticated model can simulate the development of the CO_2 plume and its associated pressure front, as well as assess the long-term fate of the injected CO_2. *GEM* has the capability to model all aspects of CO_2 storage and trapping, including residual gas trapping via relative permeability hysteresis, CO_2 dissolution into the aqueous phase, and mineral trapping.

Computational modeling will enable the development of a series of illustrative maps of the storage compartment and the vertical and areal distribution of the CO_2 plume within this storage compartment. All maps generated will use the North American Datum 1927 (NAD27) system and refer to X and Y units in ft.

The computational model will be set up to assess a two-phase water/gas system. The following formulations and methods are employed in the software to model phase behavior and relationships within the model:

- Peng-Robinson Equation of State to model gas and water phase behavior.
- CO_2 dissolution in water is modeled using Henry's solubility model, with Henry's constant as a function of temperature, pressure, and salinity.[4]
- Brine viscosity is calculated using the correlation developed by Kestin, Khalifa and Correia as a function of pressure, temperature, and salinity.[5]
- Brine density is calculated from the Rowe-Chou correlation.[6]
- CO_2 trapping due to hysteresis is modeled using Land's correlation to determine the imbibition gas relative permeability curve as a function of the given drainage curve.[7]

The methods and correlations mentioned above are used to ensure accurate phase property calculations, such as brine density due to CO_2 dissolution, brine solubility, and CO_2 trapping due to hysteresis. In addition, multiphase flow (gas/water) and buoyancy/gravity processes are modeled. These processes were included in the simulation model because they are important aspects of CO_2 sequestration into saline formations, where CO_2 dissolution in brine and CO_2 trapping due to hysteresis play a major role in immobilizing the CO_2 plume.

Another CO_2 storage method involves mineral trapping. Mineral trapping is the permanent sequestration of CO_2 through chemical reactions with dissolved minerals in the reservoir brine and with the minerals in the reservoir rock itself. However, the mineral trapping mechanism is slow and is expected to occur over very long time periods, perhaps

[4] Li, Y.; Ngheim, L. X. Phase equilibria of oil, gas, and water/brine mixtures from a cubic equation of state and Henry's law. Can. J. Chem. Eng. 1986, 64, 486-496.

[5] Kestin, J. Khalifa, H. Correia, R. 1981. Tables of the Dynamic and Kinematic Viscosity of Aqueous NaCl Solutions in the Temperature Range 20-150C and the Pressure Range 0.1-35MPa. J. Phys. Chem. Ref. Data Vol. 10, No. 1.

[6] Rowe, A.M. and Chou, J.C.S., Pressure-Volume-Temperature-Concentration Relation of Aqueous NaCl Solutions, J. Chem. Eng. Data, Vol. 15, (1970), pp. 61-66

[7] Land, C.S. 1968. Calculation of Imbibition Relative Permeability for Two- and Three-Phase Flow From Rock Properties. SPE J. 8 (2): 149–156. SPE-1942-PA.

centuries. Therefore, mineralization of the injected CO_2 is not currently included in the model. The mixing and diffusion of the CO_2 plume will, however, be continually affected following injection.[8] **Figure 4** illustrates the contribution of the key trapping mechanisms considered in the model.

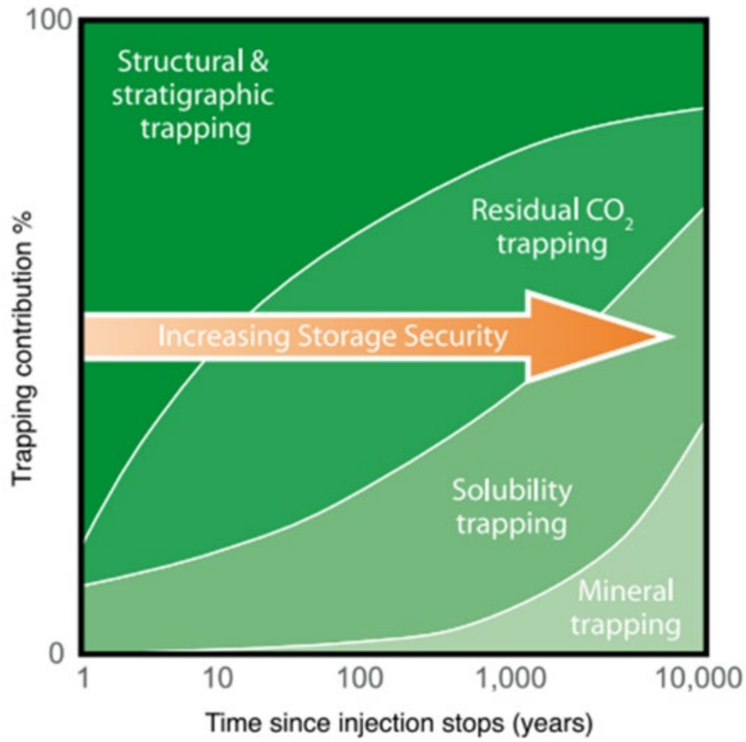

Figure 4: CO_2 Trapping Mechanisms Contribution Over Time[9]

A.3.c Computational Model Design

The Computer Modeling Group's reservoir simulator *GEM* is used for all the simulation work conducted in support of this permit application. *GEM* is an industry standard Equation of State reservoir simulator for compositional, chemical, and

[8] Pruess, K., Xu, T., Apps, J. and Garcia, J., "Numerical Modeling of Aquifer Disposal of CO_2," SPE paper 66357 presented at the SPE/EPA/DOE Exploration and Production Environmental Conference, San Antonio, Texas, 26-28, February 2001

[9] IPCC, 2005: IPCC Special Report on Carbon Dioxide Capture and Storage. Prepared by Working Group III of the Intergovernmental Panel on Climate Change [Metz, B., O. Davidson, H. C. de Coninck, M. Loos, and L. A. Meyer (eds.)]. Cambridge University Press, Cambridge, United Kingdom and New York, NY, USA, 442 pp.

unconventional reservoir modeling that is fully capable of accurately modelling the long-term effects of CO_2 injection into saline reservoirs.

A.3.c.1 Model Discretization

The model uses a rectangular tartan grid system (smaller grid blocks in the area of the injection wells with larger grid blocks further away from the injection wells) with 73 grid cells in the x-direction and 74 grid cells in the y-direction. Individual grid blocks around the injectors are 400 ft by 400 ft, while grid blocks further away are 1,600 ft by 1,600 ft (**Figure 5)**. Geologic properties (depth, thickness, permeability, and porosity) are assigned to each grid cell to reflect the subsurface characteristics derived from the geologic assessment. Formation top depths are imported into the simulation model from *Petrel* (robust geologic modeling software). Grid depths are then internally calculated from the depth maps. Thickness values are internally calculated for each cell by subtracting the top depth of the cell and the top depth of the cell below it. Uniform average porosity and permeability values are assigned to each grid layer. The model dimensions are 10.6 miles north-south and 9.7 miles east-west providing a storage area of nearly 103 square miles (65,920 acres) **(Figure 5)**.

Due to the extensive thickness and variability of the Paluxy formation, the Paluxy was first vertically subdivided into an Upper Paluxy and a Lower Paluxy, four injection intervals were established in the Upper Paluxy, and two injection intervals were designed for the Lower Paluxy, with notable layers of shales separating the injection intervals.

Each of these injection intervals contains multiple reservoir layers to achieve a better resolution of the CO_2 plume extent and to model buoyancy effects. This resulted in 50 sub-layers in the Upper Paluxy and 25 sub-layers in the Lower Paluxy. Additional shale sub-layers were used to represent the overlying Wash-Fred Basal Shale confining unit and the underlying Mooringsport Formation. As a result, the model has a total of 86 sub-layers in the vertical direction and a total of 464,572 grid blocks.

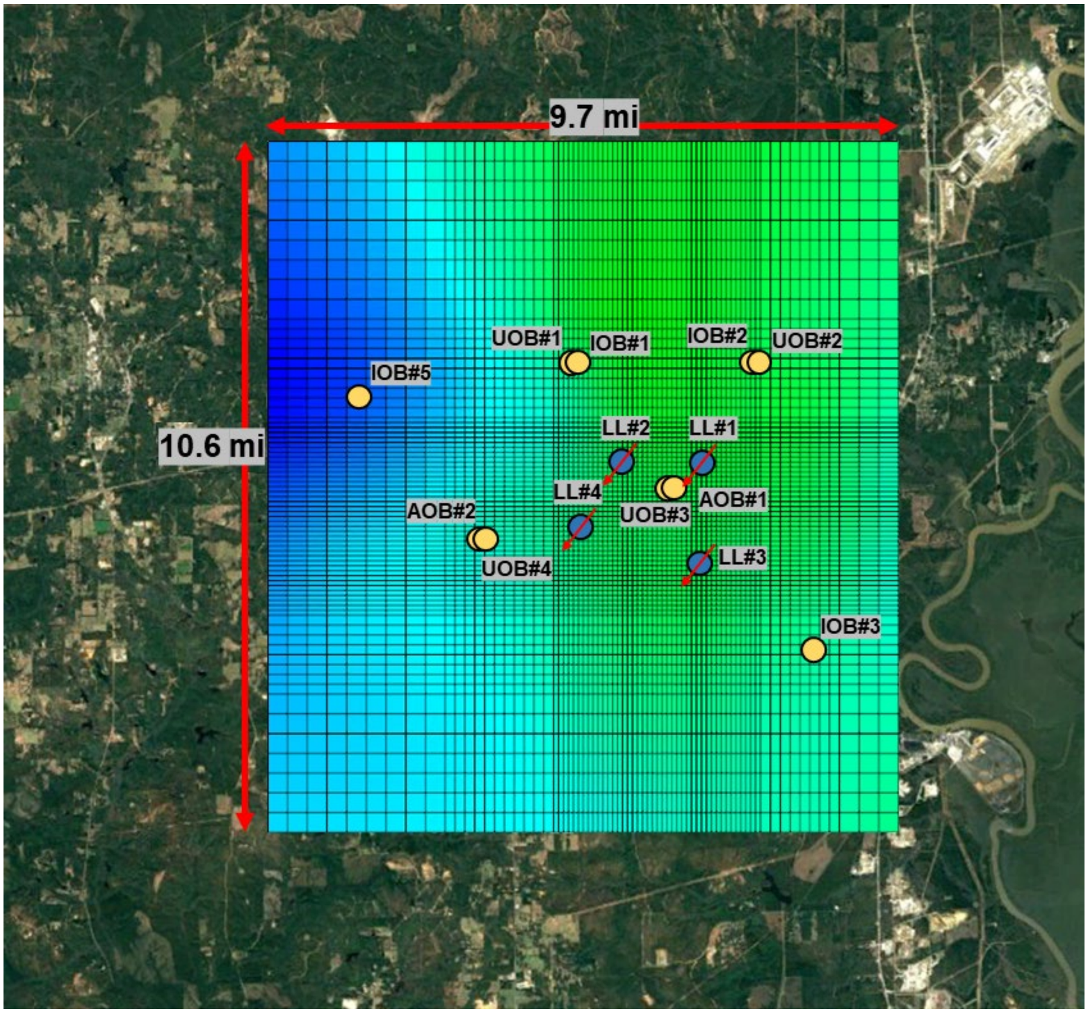

Figure 5: Top View of the Model Area

Figure 6 shows a 3D oblique view of the reservoir model, highlighting the Upper and Lower Paluxy injection intervals, the Wash-Fred Basal Shale (secondary confining unit), the Mooringsport Formation (lower confining unit), and the proposed well locations. Note the 14 times vertical exaggeration of the grid blocks to show the model layers.

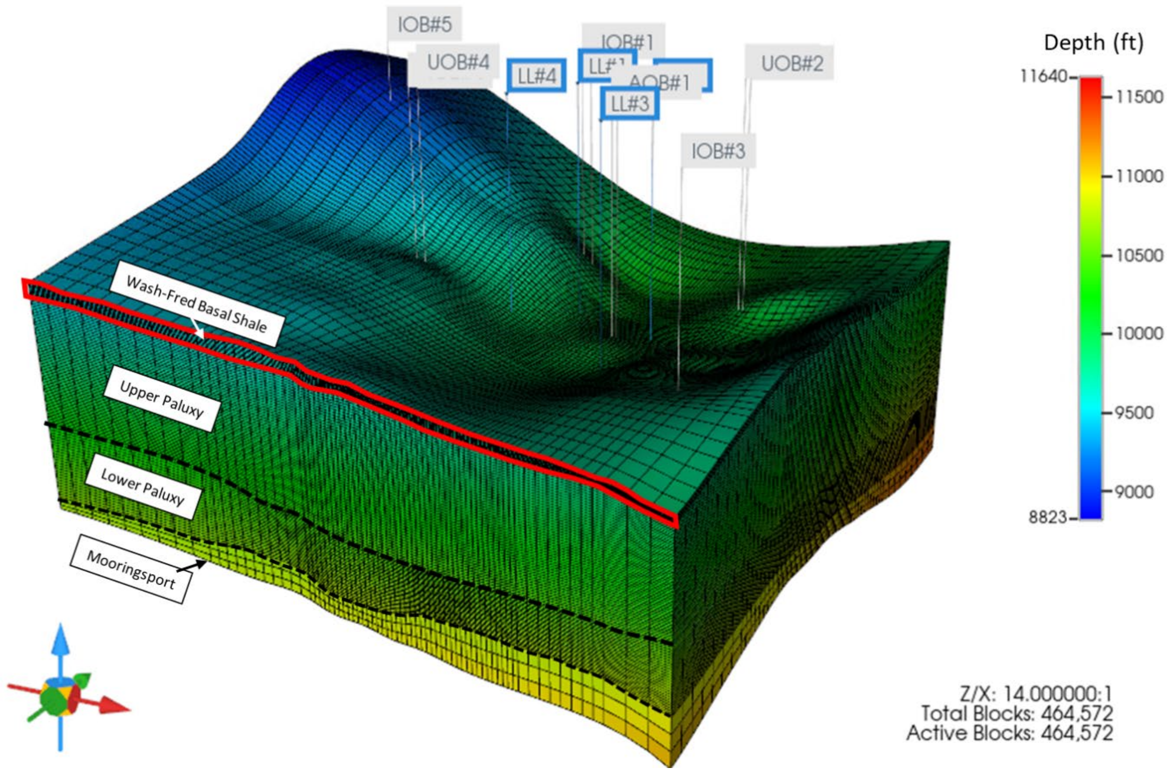

Figure 6: 3D Oblique View Map of the Reservoir Model (14x vertical extent)

A.3.c.2 Model Domain

An understanding of the regional and local subsurface geology is essential to accurately assess the injection reservoir and model the subsurface injection and flow of CO_2. Based upon interpretation and evaluation of geophysical well logs, core analysis and 2D seismic analysis, a comprehensive picture of the subsurface geology has been developed for the Longleaf CCS Hub (see ***Application Narrative***). These values were used in the reservoir simulation model to estimate fluid flow, pressure, and CO_2 storage processes. These parameters (elevation, thickness, porosity, permeability, etc.) are detailed in upcoming sections. The model domain information is summarized in **Table 3**.

Table 3: Model Domain Information

Coordinate System	North American Datum 1927 (NAD27)		
Horizontal Datum	(KG0640) MEADES RANCH		
Coordinate System Units	US FEET		
Zone	Clarke 1866		
FIPSZONE	0102	**ADSZONE**	3126
Coordinate of X min	1,270,000	**Coordinate of X max**	1,319,600
Coordinate of Y min	11,250,400	**Coordinate of Y max**	11,304,800
Elevation of bottom of domain	-11,640 ft	**Elevation of top of domain**	-8,823 ft

A.3.c.3 Model Parameters

As detailed in the ***Application Narrative***, six individual Paluxy Sandstone intervals were identified as potential storage reservoirs for CO_2. The average depth to top, average thickness, and net to gross ratio of the six Paluxy injection intervals and two confining units near the four injection wells are shown in **Table 4**. The elevations and gross thicknesses for the 8 horizons as defined by the 3D Static Earth Model generated in Schlumberger's *Petrel* geomodelling software were directly input to the simulation model. **Figures 7a and 7b** are an illustration of the elevation for the top Paluxy sandstone and total thickness map for the Paluxy Formation.

Table 4: Model Elevation, Thickness, and Net to-Gross-Ratio Per Formation

Flow Unit	Average Top MD (ft)	Thickness (ft)	Net to Gross Ratio
Wash-Fred Basal Shale	9,990	95	1
Upper Paluxy Zone 1	10,130	50	1
Upper Paluxy Zone 2	10,215	50	1
Upper Paluxy Zone 3	10,300	202	0.63
Upper Paluxy Zone 4	10,680	101	0.67
Lower Paluxy Zone 1	11,060	24	1
Lower Paluxy Zone 2	11,160	48	1
Mooringsport	11,220	175	1

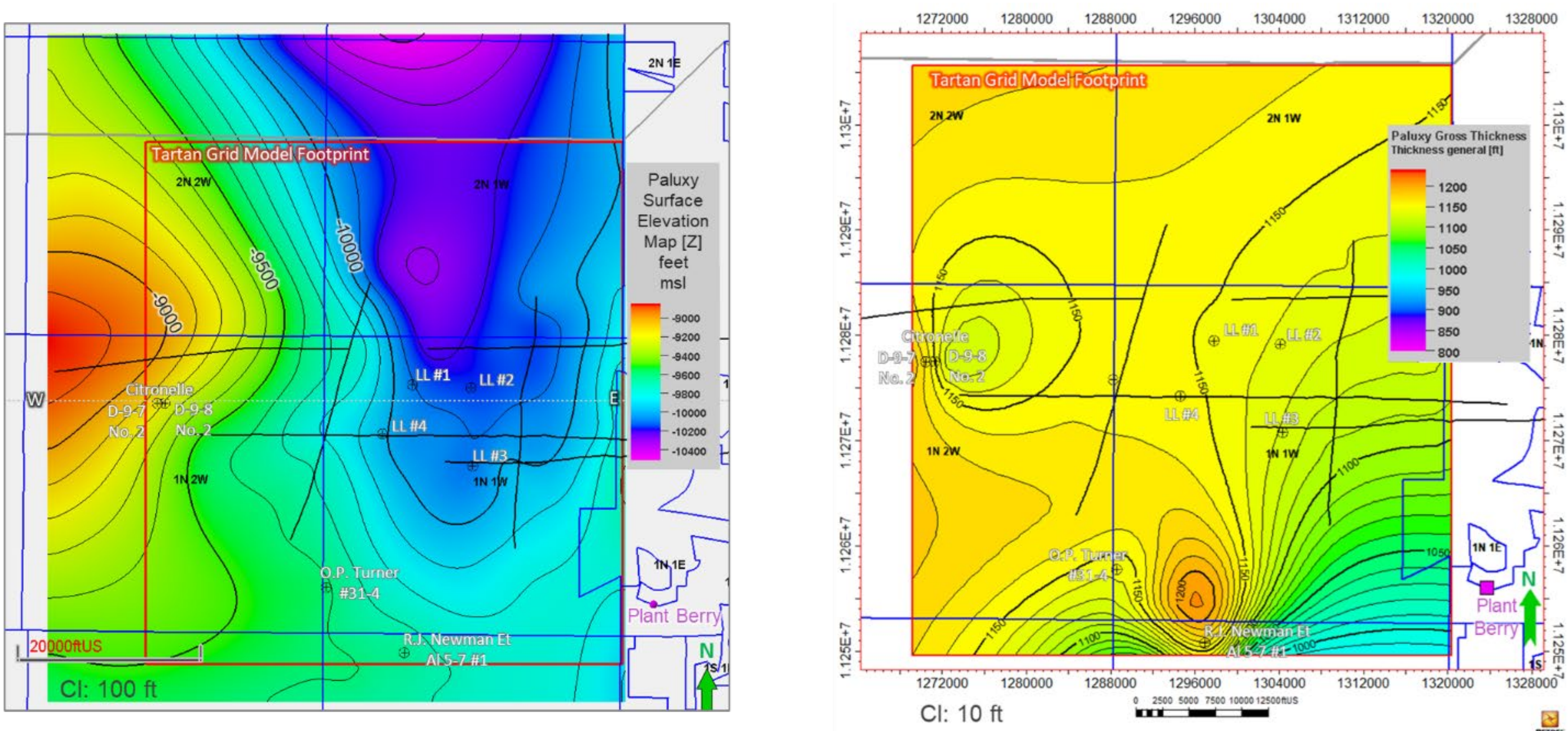

Figure 7: Structural Elevation Map of Paluxy (a) and Paluxy Thickness Map (b)

A.3.c.4 Boundary Conditions

The Mobile Graben is located to the east of the Longleaf CCS Hub. The computational model boundary was constructed up to the Mobile Graben barrier along the northeast edge of the model. Moving south, the Mobile Graben shifts away from the model boundary approximately 8,000 ft. A conservative estimate was used for the model to allow for horizontally transmissive fluid and pressure flow from the Longleaf CCS Hub reservoirs across the Mobile Graben barrier.

In the other three directions, the model was designed as an open boundary system as there are no geological or petrophysical features that act as fluid or pressure propagation boundaries in these three directions of the storage area (see **Section 1.2** of the ***Application Narrative***).

A pore volume multiplier of 10,000 was applied to the outer layer of vertical grid cells along the perimeter of the model facing north, west, and south in order to approximate an open-boundary system behavior. Pore volume modifiers increase the pore volume of the reservoir model without having to include additional grid blocks in the reservoir model. This helps to reduce the grid extent and runtime of the model.

A.3.c.5 Model Timeframe

Per 40 CFR 146.84(c)(1), the model is required to run from the beginning of injection activities until the plume movement ceases or until the pressure differential sufficient to lift fluids to the USDW is no longer present. As such, the modelling was conducted for a total of 50 years, with the first 30 years covering the injection period and the following 20 years covering the post-injection monitoring period. At 20 years post injection, the migration rate of the CO_2 plume slows considerably (compared to the injection period), the movement of the CO_2 plume is predictable within the reservoir, and the reservoir pressure is below the minimum pressure required to lift fluid from the injection reservoir to the lowest USDW (described further in **Section A.4.a** *Determination of Pressure Threshold Front*)

A.3.c.6 Model Parameters

A.3.c.6.1 Porosity and Permeability

Saline Reservoir Porosity. Porosity values for the Paluxy formation were derived using an average of the neutron porosity and density porosity logs at the D-9-8 #2 Citronelle well. For a better description of the CO_2 plume, each of six Paluxy injection intervals was further sub-divided into a series of sub-layers. The corresponding average porosity values and range of porosity values are summarized in **Table 5** for the six Paluxy injection intervals.

Table 5: Average Porosity and Permeability Estimates for Each Perforated Paluxy Interval

Injection Interval	Average Porosity (%)	Porosity Range (%)
Upper Paluxy Zone 1	15.8	12.7–19.3
Upper Paluxy Zone 2	13.0	9.6–19.2
Upper Paluxy Zone 3	12.8	9.1–16.1
Upper Paluxy Zone 4	11.9	8.2–14.3
Lower Paluxy Zone 1	9.4	8.4–10.4
Lower Paluxy Zone 2	13.1	10.3–16.0

The variation in porosity, by layer, is shown in **Figure 8**. The highest average porosity is observed in the sandstone layers within the top portion of the Upper Paluxy interval. The Wash-Fred basal shale confining seal, Mooringsport shale, and interbedded shale layers are shown in the model with relatively low average porosity values.

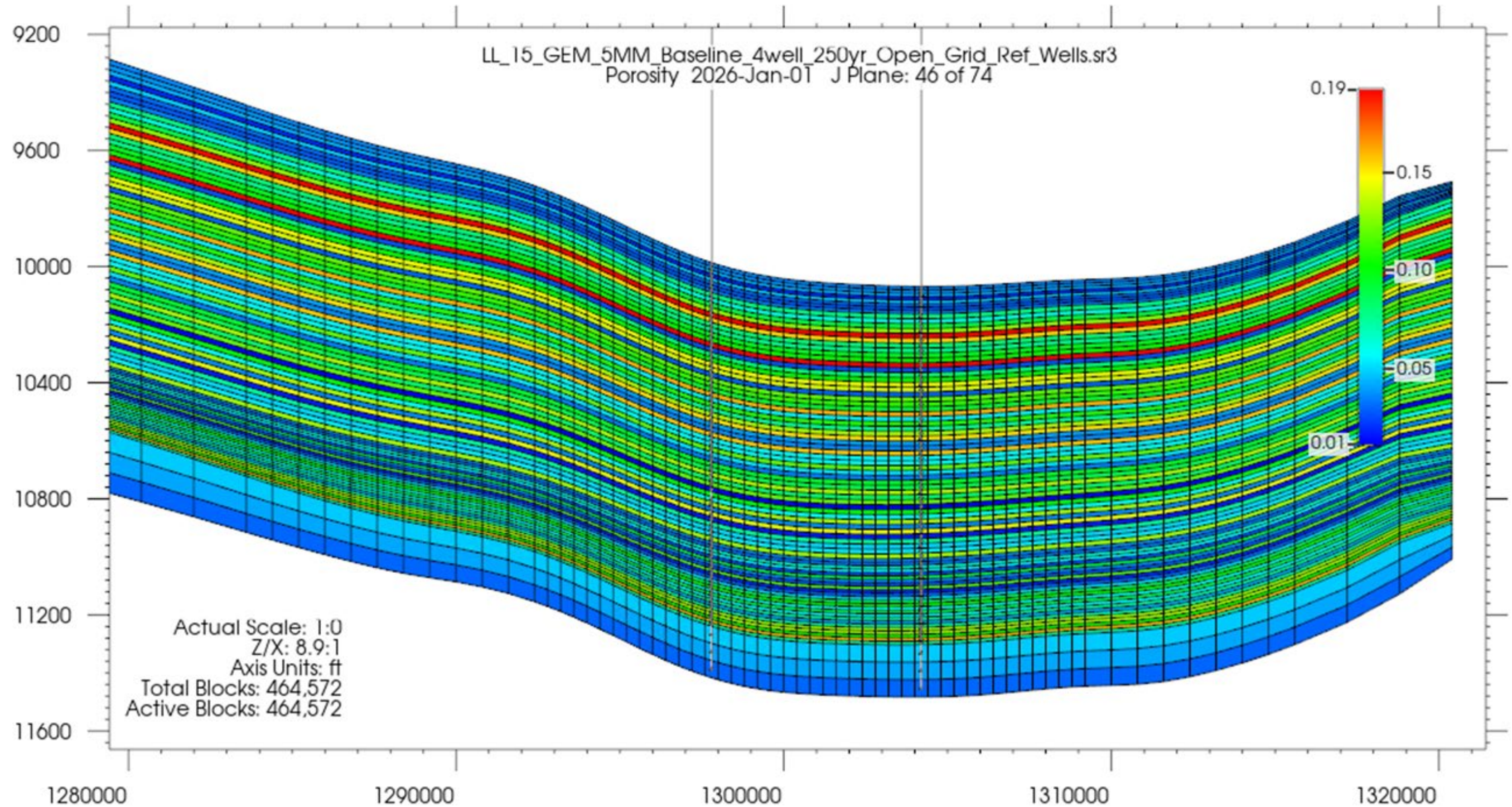

Figure 8: Longleaf CCS Hub Reservoir Model Porosity (fraction) Variation by Layer (9x vertical extent)

Saline Reservoirs Permeability. For each target formation, permeability-porosity correlations were developed using the collected log data as well as available core data. The porosity-permeability relationship is shown in **Figure 9**. These transform functions are used to calculate the average horizontal permeability within each reservoir, assuming isotropic permeability. A vertical to horizontal permeability ratio of 0.1 was then used to calculate the vertical permeability from the horizontal permeability. Horizontal permeability values are summarized in **Table 6** for the Paluxy Sandstone.

Table 6: Injection Zone (Paluxy) Horizontal Permeability Estimates

Injection Interval	Average Permeability (mD)	Permeability Range (mD)
Upper Paluxy Zone 1	223.2	93.9–406.8
Upper Paluxy Zone 2	172.0	37.5–436.8
Upper Paluxy Zone 3	105.6	27.8.–225.1
Upper Paluxy Zone 4	64.9	26.2–98.4
Lower Paluxy Zone 1	30.8	24.5–37.2
Lower Paluxy Zone 2	74.5	44.5–115.1

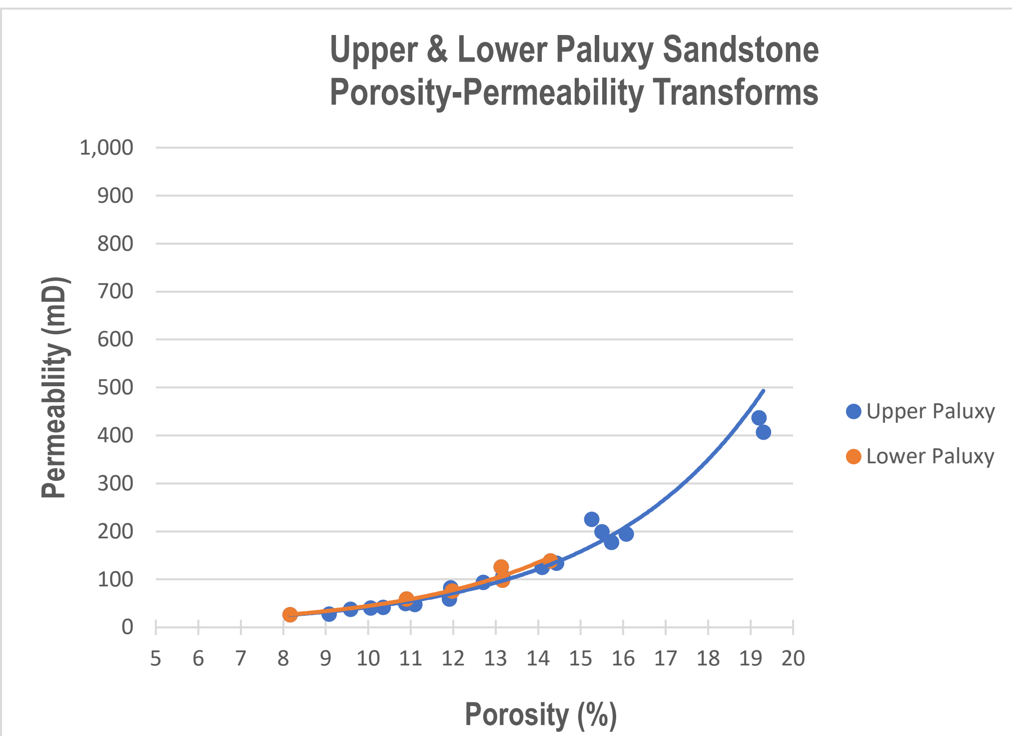

Figure 9: Longleaf CCS Hub Model Permeability-Porosity Transforms

Shale Permeability. Pulse decay permeability measurements were obtained for the Basal Shale of the Wash Fred and the Tuscaloosa Marine Shale from the work on the Citronelle wells along the western edge of the Longleaf CCS Hub. Based on the measurement from the shale intervals, values between 10 to 100 nD ($1.0*10^{-4}$ to $1.0*10^{-5}$ mD) were applied to each of the shale confining layers based on estimated values for the porosity in each shale layer. A cross section of the reservoir model is shown in **Figure 10,** highlighting the permeability variations among the sand and shale layers.

A.3.c.6.2 Formation Structure

The structural interpretations for the injection and confining units from the 3D Static Earth Model were loaded in the computational model providing a rigorous description of the structural dip within the Longleaf CCS Hub.

A.3.c.6.3 Relative Permeability Curves

The relative permeability data used for this study were based on work conducted in the Paluxy formation at the Anthropogenic Test Site at Citronelle, Alabama.[10] These analog curves were generated through history matching the CO_2 injection history pressure and CO_2 breakthrough response at multiple monitoring well locations. Based on literature research regarding drainage and imbibition CO_2/brine relative permeability curves,[11] [12] the maximum relative permeability to gas was set to 0.65. The resulting curves are shown in **Figure 11**.

Relative permeability data was not available for the confining units at the Longleaf CCS Hub. The relative permeability curves used were from the Calmar formation of the Alberta Basin, reported by Bennion and Bachu, 2007.[13] The Calmar formation was chosen as a proxy because its properties (lithology and pore structure for example) are similar to

[10] Advanced Resources International, 2013. Special Topical Report, Report of Advanced Core Analyses: Relative Permeability and Permeability vs. Throughput for Citronelle SECU D-9-8 #2.

[11] Bachu, Stefan. 2011. Drainage and Imbibition CO_2/Brine Relative Permeability Curves at In-situ Conditions for Sandstone Formations in Western Canada. GHGT 11, Kyoto, Japan.

[12] Krevor, S. Pini, R. Zuo, L. Benson, S. 2012. Relative Permeability and Trapping of CO_2 and Water in Sandstone Rocks at Reservoir Conditions. Water Resources Research, Volume 48, W02532.

[13] Bennion, B. D., & Bachu, S. (2007). Permeability and relative permeability measurements at reservoir conditions for CO_2-Water systems in ultra low permeability confining caprocks. Society of Petroleum Engineers.

the properties at this study area. This set of curves represent a very low permeability shale rock with high irreducible water saturation and very low gas relative to permeability. Relative permeability curves for the confining units are illustrated on **Figure 12**.

A.3.c.6.4 Capillary Pressure

Shale capillary pressure curves show very high capillary entry pressure values (over 7,000 psi from 23 samples in the Tuscaloosa Marine Shale and 8 samples in the Lower Tuscaloosa Shale) (Lohr and Hackley, 2018).[14] These high entry capillary pressures mean that the CO_2 pressure in the injection zone needs to exceed these values to enter the 100% brine saturated caprock pores. Capillary pressure values for the Wash-Fred Basal Shale were not available. However, because of the very low permeability of these shale layers, the reservoir model shows that CO_2 stays within the Paluxy Formation and does not migrate into the Wash-Fred Basal Shale.

A.3.c.6.5 Rock Compressibility

The Hall correlation (Hall, 1953)[15] was used to compute the rock compressibility of the Paluxy Sandstone, which is shown below in **Equation 1**.

Equation 1

$$c_f = \left(1.782/\phi^{0.438}\right)10^{-6} \qquad (1)$$

[14] Celeste D. Lohr and Paul C. Hackley (2018), Using mercury injection pressure analyses to estimate sealing capacity of the Tuscaloosa marine

[15] Hall, Howard N., 1953. Compressibility of Reservoir Rocks. J Pet Technol 5 (1953): 17–19. doi: https://doi.org/10.2118/953309-G

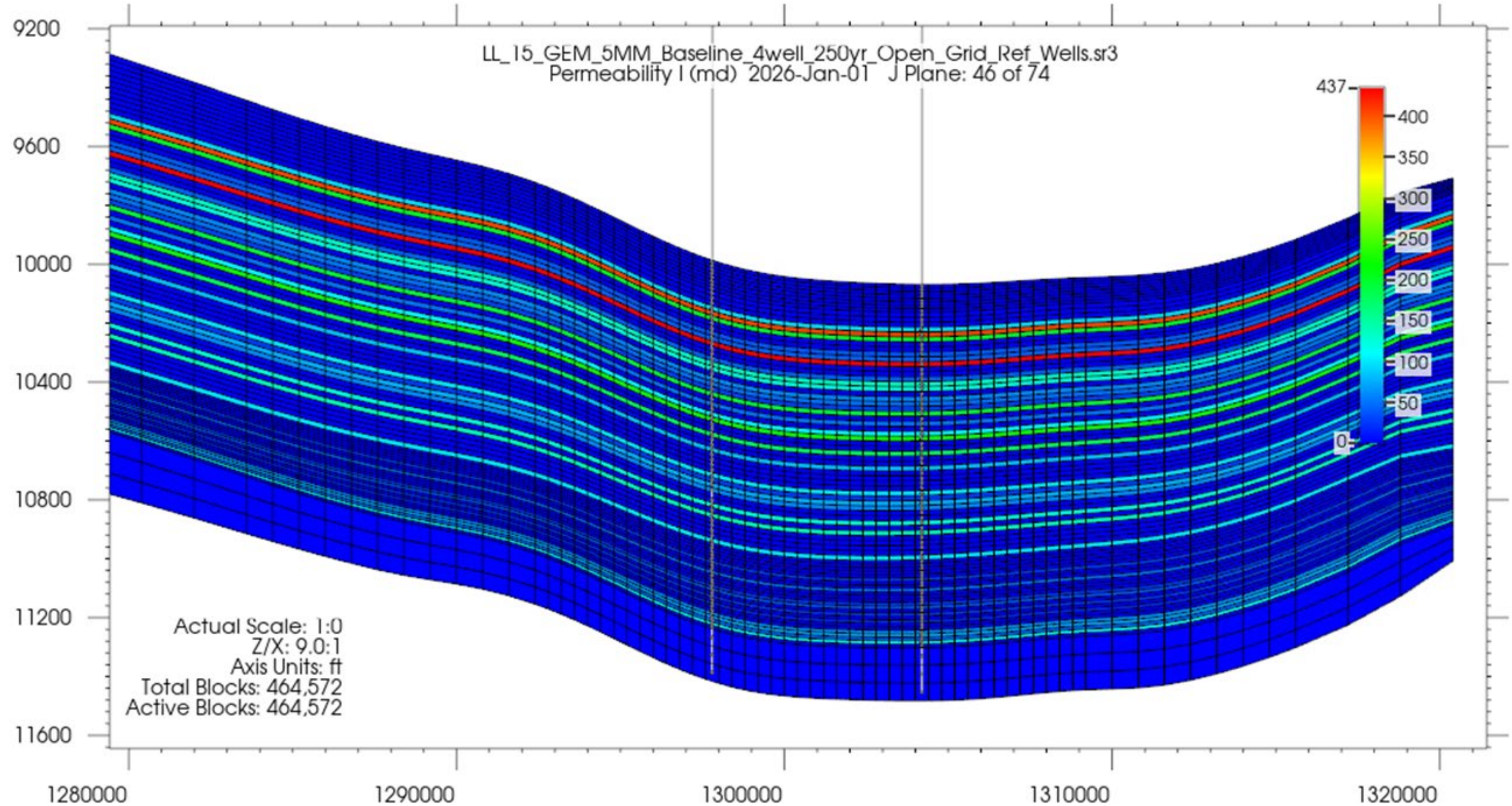

Figure 10: Longleaf CCS Hub Reservoir Model Permeability Variation by Layer (9x vertical extent)

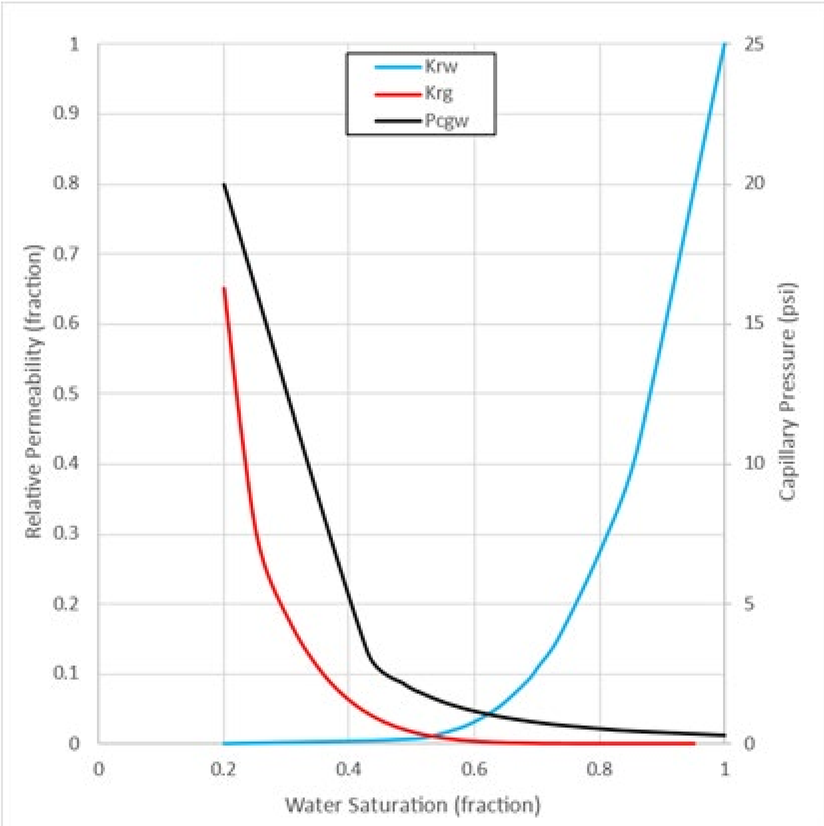

Figure 11: Longleaf CCS Hub Model Sandstone Unit Relative Permeability Curves

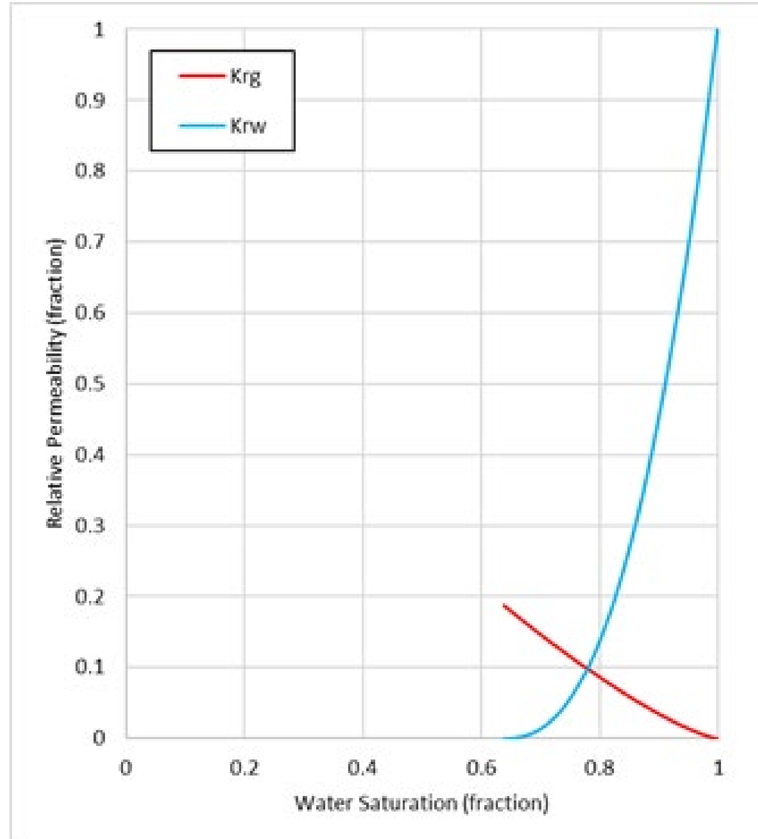

Figure 12: Longleaf CCS Hub Model Confining Unit Relative Permeability Curves

The correlation is based on laboratory data and is considered reasonable for normally pressured sandstones. With porosity in the Paluxy varying from 8.2% to 19.3%, the corresponding compressibility varies between $5.33e^{-6}$/psi and $3.66e^{-6}$/psi. The weighted average of $4.43e^{-6}$/psi was used in the model.

<u>Initial Reservoir Pressure</u>

The pressure gradient at the Longleaf CCS Hub is 0.463 psi/ft based on gauge data collected from the D-9-8 #2 Paluxy in-zone monitoring well at Citronelle Dome, as shown in **Table 7**.[16] This pressure gradient was used for initial pressure conditions in the reservoir model.

Table 7: Longleaf CCS Hub Reservoir Pressure Gradients

Hydrogeologic Unit	Reservoir Pressure (psi)	Gauge Depth (ft)	Pressure Gradient (psia/ft)	Source
Paluxy	4,385	9,441	0.463	D-9-8 #2 Monitoring Well

A.3.c.6.6 Reservoir Temperature

Formation temperatures were collected from the D-9-8 #2 Paluxy in-zone monitoring well at Citronelle Dome located at the eastern portion of the study area.[16] This data provided a temperature gradient that was applied to the reservoir model. This data is summarized in **Table 8**. Reservoir reference depths and temperature values based on the 1.65 °F/100ft temperature gradient were used as inputs in the reservoir model. Reservoir temperature values were then automatically calculated for the reservoir layers in the model by depth.

[16] Freifeld, B. et al. "The Modular Borehole Monitoring Program: a research program to optimize well-based monitoring for geologic carbon sequestration". Energy Procedia 63 (2014) 3500-3515.

Table 8: Longleaf CCS Hub Reservoir Temperatures

Hydrogeologic Unit	Monitoring Well	Gauge Depth (ft)	Temperature (°F)	Temperature Gradient (°F/100ft)
Paluxy	D-9-8 #2	9,441	224	1.65

A.3.c.6.7 Water Salinity

Water samples from the Paluxy formation were acquired from the Citronelle D-9-8 #2 characterization well.[17] This sampling data provided a salinity value of approximately 200,000 mg/l (**Table 9).** This value was directly input into the model.

Table 9: Longleaf CCS Hub Formation Water Salinities

Formation	TDS (mg/l)	Source
Paluxy	200,000	D-9-8 #2 Water Analysis

A.3.d Executing the Computational Model

A.3.d.1 Predictions of System Behavior

The pressure front created by the injection of CO_2 into the Paluxy formation extends uniformly from the injection wells. The greatest change in pressure occurs within the first two years of injection, close to the injection wellbores. The maximum change in pressure is 694 psi, or about a 15% difference from initial conditions. **Figure 13** exhibits a map of the pressure buildup (current minus initial pressure) in the top sand layer two years after the start of injection.

[17] Conaway, C.H. et al. “Comparison of geochemical data obtained using four brine sampling methods at the SECARB Phase II Anthropogenic Test CO2 site, Citronelle Oil Field, Alabama.” International Journal of Coal Geology 162 (2016) 85-95.

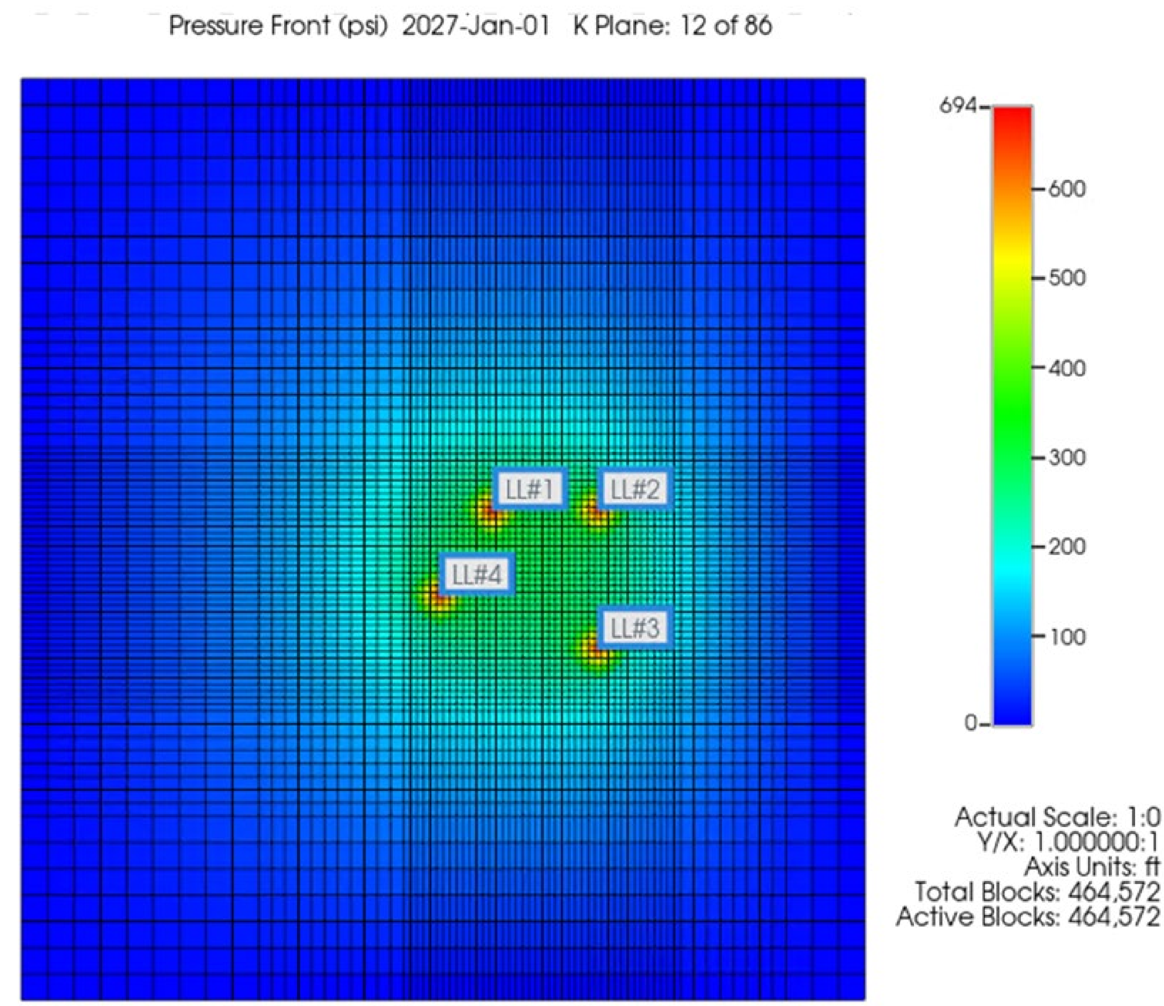

Figure 13: Change in Pressure from Initial Conditions Two Years after Start of Injection (psi)

The variation in the pressure change from initial conditions begins to even out across the area of injection in the model after two years of injection. By the end of the 30-year injection period, the maximum change in pressure from initial is approximately 450 psi, observed near the injection wellbores, **Figure 14**.

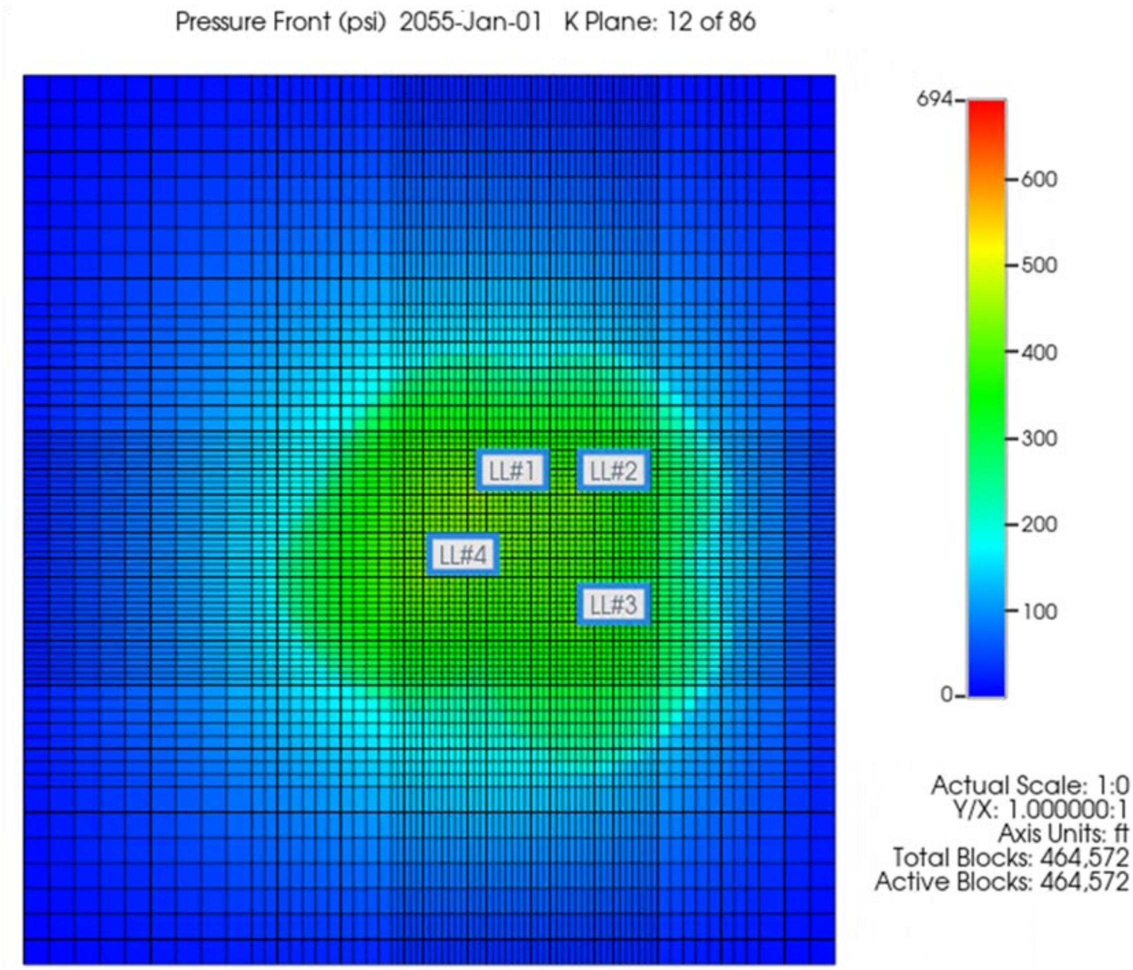

Figure 14: Pressure Increase from Initial Conditions at the End of Injection (psi)

During the post-injection period, reservoir pressure drops significantly and declines toward original reservoir pressure. **Figure 15** shows the pressure front two years following the end of CO_2 injection. The maximum pressure difference from initial conditions is approximately 186 psi. Three years post-injection, the pressure front declines to below the critical pressure value of 166 psi that is required to lift reservoir fluids to the lowest USDW within the Longleaf CCS Hub. At this time, the maximum pressure value in the pressure front is approximately 110 psi greater than initial conditions. By five years post-injection, the pressure front is reduced to between 20 psi and 50 psi greater than initial conditions.

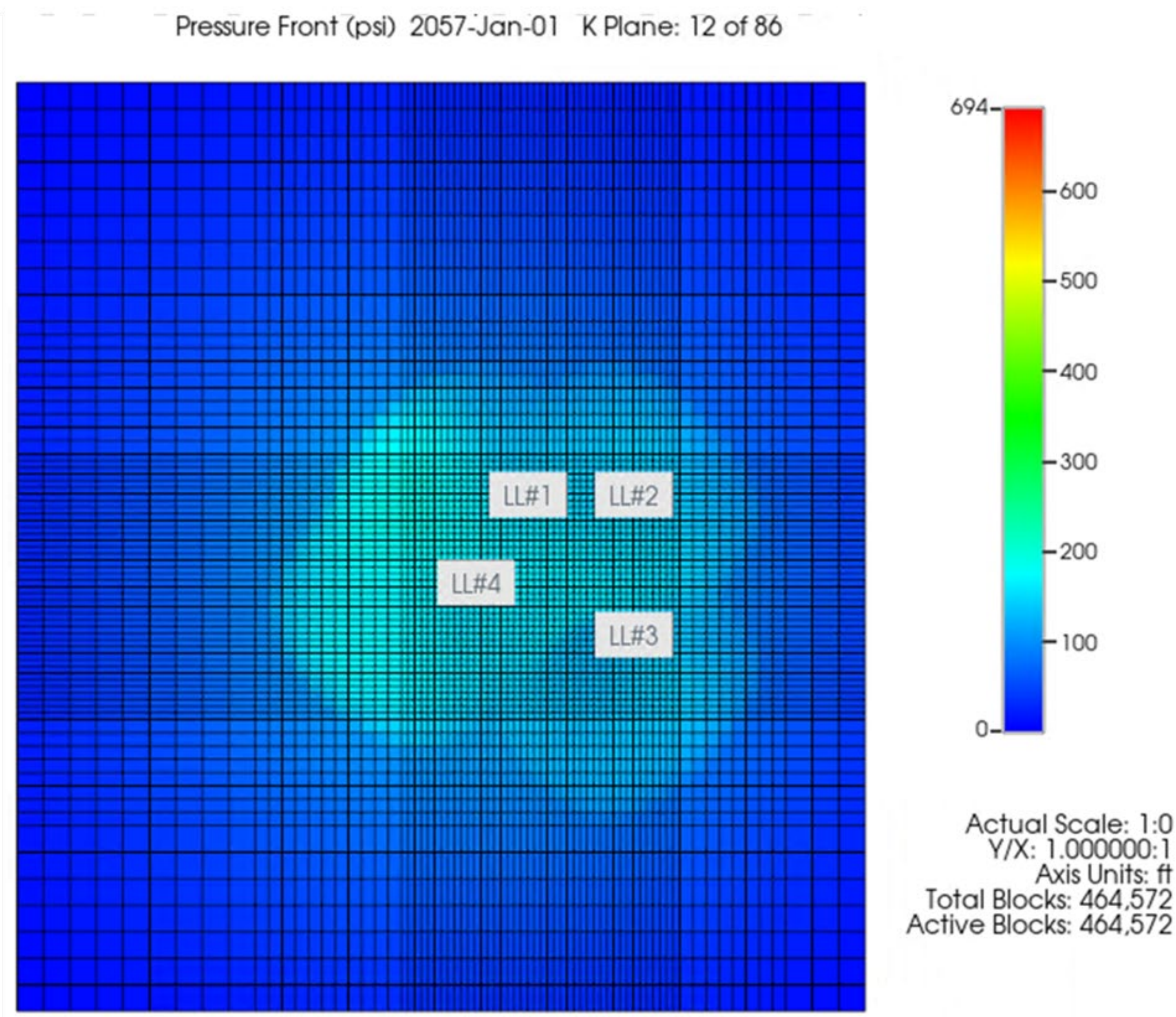

Figure 15: Pressure Increase from Initial Conditions Two Years after the End of Injection

Figure 16 shows the aerial view of the CO_2 plume at the end of injection. The Upper Paluxy Zone 1 sandstone is the geologic portion of the reservoir model with the greatest CO_2 plume extent. This is expected due to its location at the top of the Paluxy injection intervals and more favorable permeability and porosity values compared to the other injection intervals. Upper Paluxy Zone 1, and specifically Layer 12, is used to determine the maximum CO_2 plume extent. At the end of injection, the CO_2 plume measures approximately 5.6 miles from east to west and 5.2 miles from north to south.

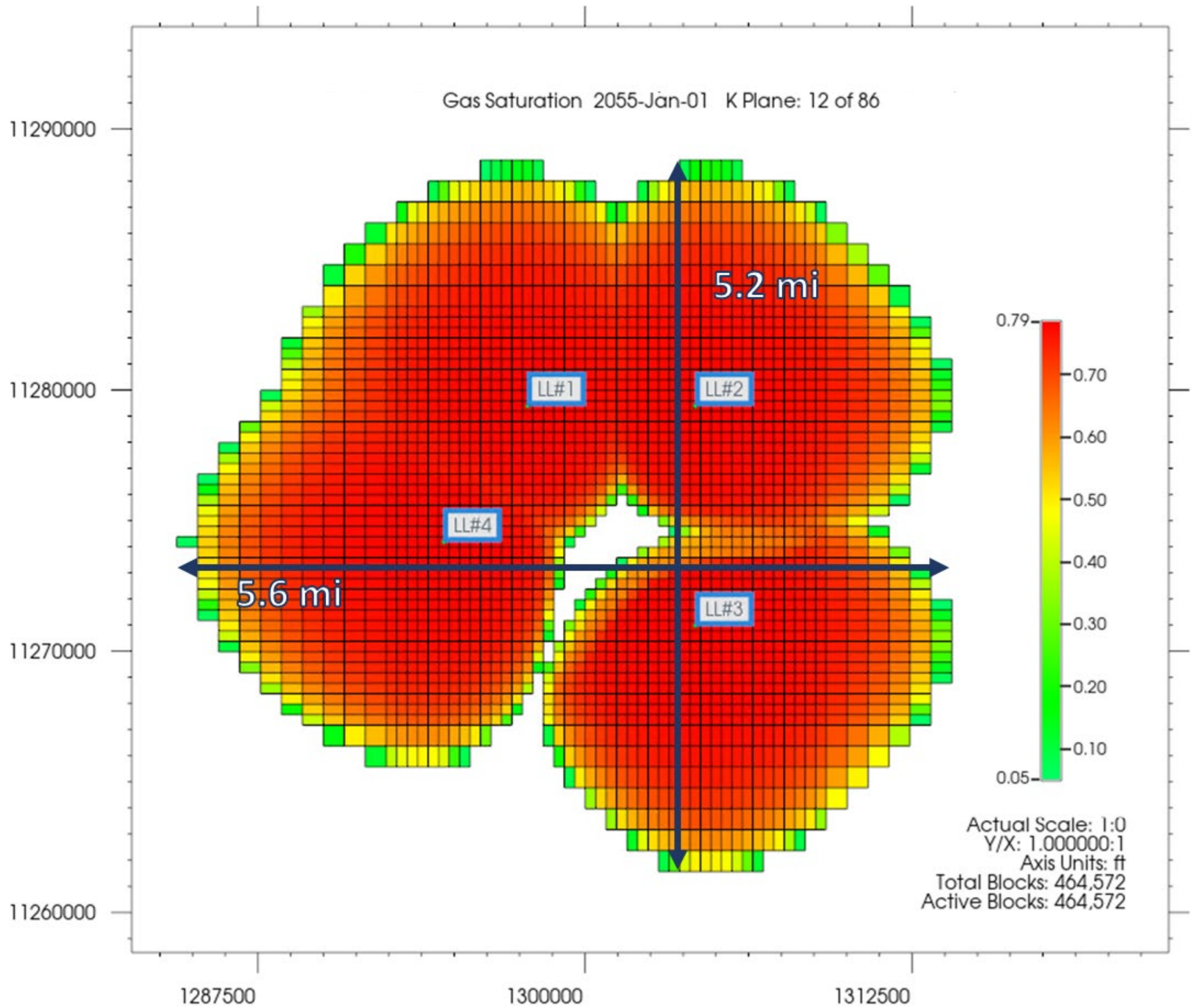

Figure 16: Aerial View of Largest CO_2 Plume Extent (Model Layer 12) at the End of 30-year Injection

Figure 17 shows the extent of the CO_2 plume over time georeferenced to the location of the injection wells. The map shows the maximum extent of the CO_2 plume during 5, 10, and 20 years of injection, at the end of the 30-year injection period, and 5, 10, and 20 years post end of injection. The map shows the CO_2 plume extending in a symmetrical pattern outward from each injection well during the 30-year injection period. Following the end of injection, the CO_2 plume moves in a predictable manner in the up-dip direction of the reservoir structure to the northwest, southwest, and southeast. Notably the CO_2 plume ceases movement to the north, northeast, and east directions following the end of injection as reservoir pressure returns to initial conditions.

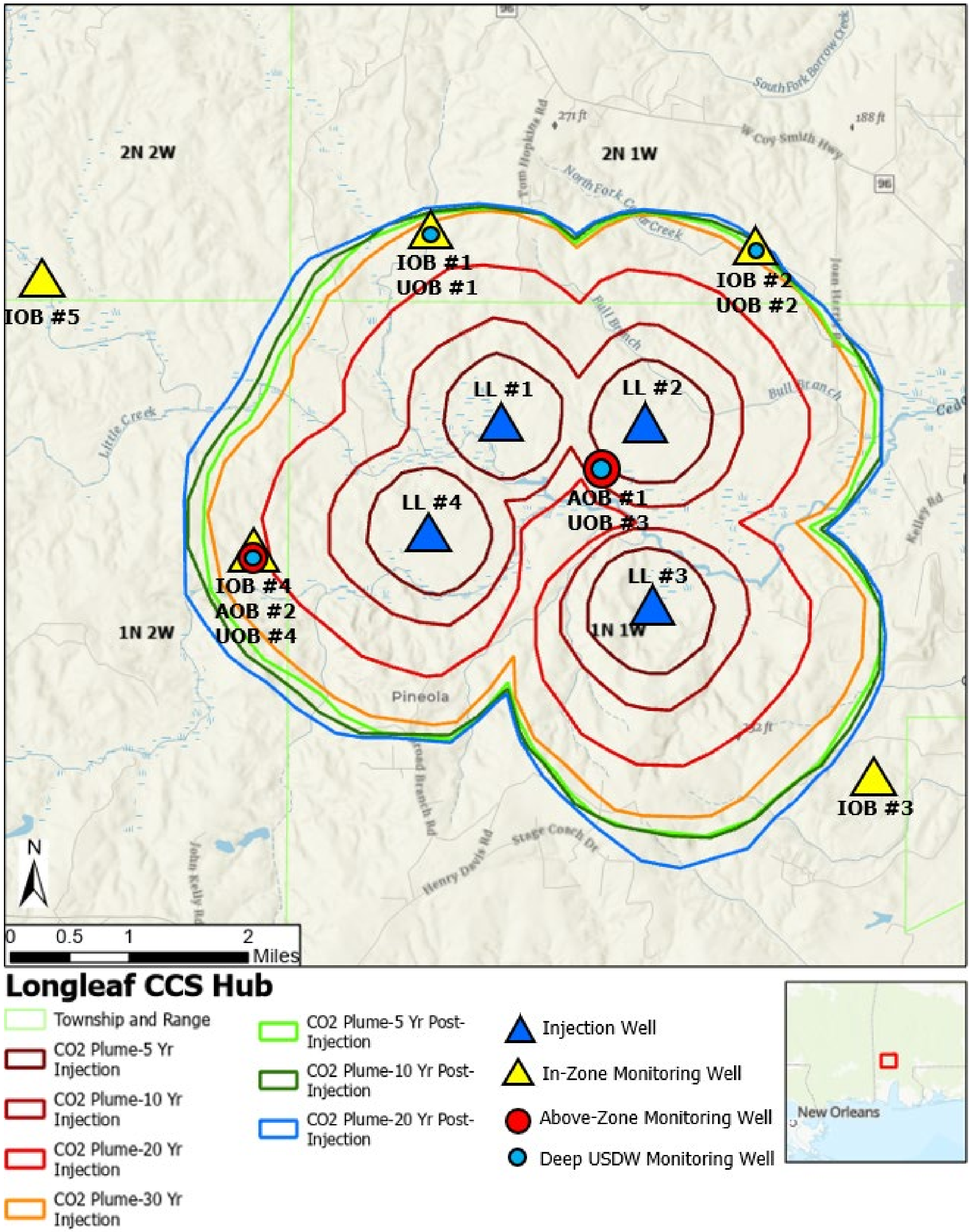

Figure 17: Evolution of CO_2 Plume Extent To 20 Years Post End of Injection

The CO_2 plume travels the greatest distance to the west from injection well LL#1 during CO_2 injection. The CO_2 plume travels approximately 10,400 ft, or an average rate of about 347 ft/yr to the west during the 30-year injection period. Similarly, the plume moves outward from the injection wells to the north, east, and south an average distance of about 10,000 ft during the 30-year injection period, or about 333 ft/yr.

From the end of injection to the end of the proposed 20-year monitoring period (post-injection), the CO_2 plume migrates a maximum of 2,400 ft, also to the west from injection well LL#1. The rate of migration of the CO_2 plume post-injection slows to 120 ft/yr or about 1/3 of the rate of expansion during the 30-year injection period. The CO_2 plume migrates an average of about 800 ft to the north, east, and south during the 20 years post-injection monitoring period, or an average of 40 ft/yr before the plume effectively ceases migration in these directions.

Figure 18 shows a 3D view of the CO_2 plume at the end of 20 years post-injection, both A) facing north and B) a side-profile view with a cutaway of the CO_2 plume between LL#1/LL#2 and LL#3/LL#4. This CO_2 plume extent corresponds to the outline of the CO_2 plume shown in **Figure 17**. The model shows the detail of the reservoir structure and CO_2 accumulation throughout the sandstone layers in both the Upper and Lower Paluxy. The figure also shows the CO_2 plume has the greatest aerial extent in the top layer of the model, Layer 12, as expected. The CO_2 accumulations in the sandstone layers are confined by the interbedded shale layers within the Paluxy. The figure shows that the CO_2 plume ceases expansion to the north and east while slowly migrating along the up-dip reservoir structure to the west.

At the end of 20 years of monitoring, what is left of the mobile CO_2 plume exhibits slow, predictable migration up-dip from the injection well locations to the northwest, southwest, and southeast. The concentration of the CO_2 plume diminishes over time as more CO_2 is trapped in pore space and dissolves in reservoir brine, reducing the volume of mobile CO_2 within the plume.

Understanding the long-term fate of the injected CO_2 is paramount to ensuring a safe and secure storage project. As mineral information is not available at this phase of the project, mineral trapping is not considered. Solubility trapping and relative permeability hysteresis trapping are the only two trapping mechanisms considered.

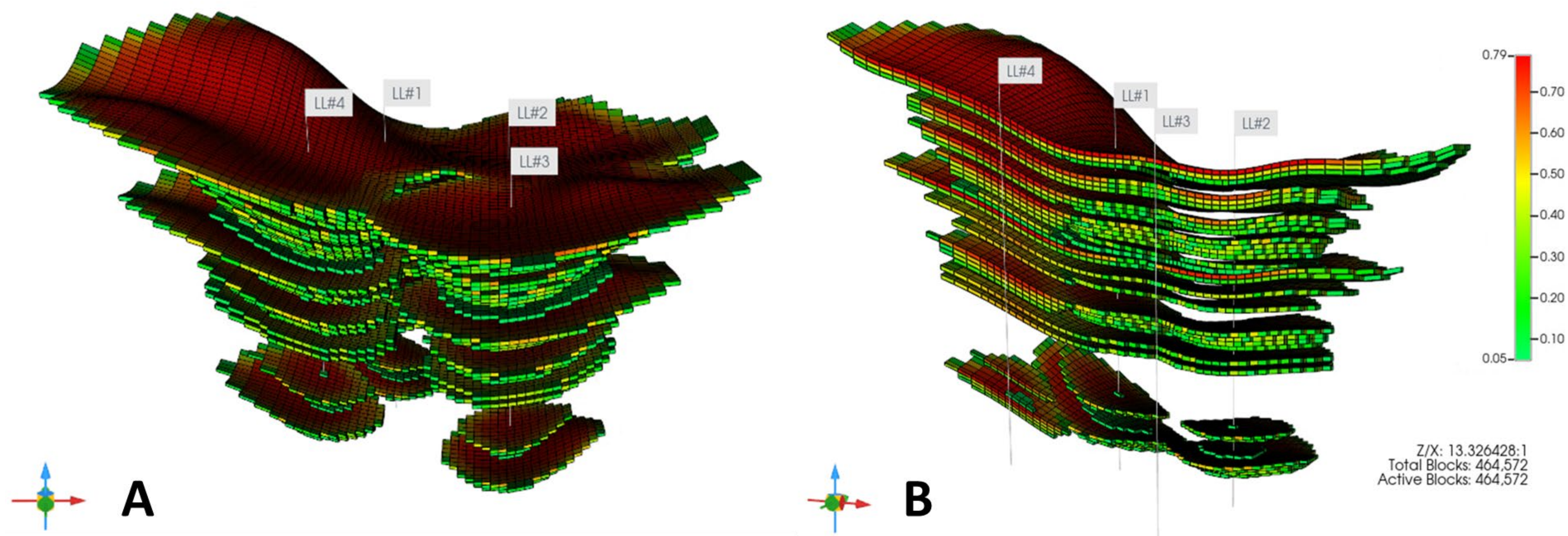

Figure 18: Cross Section of the CO_2 Saturation Plume 20 Years Post-Injection

CO_2 is soluble in water, and when injected into a pressurized saline reservoir, some of the CO_2 will dissolve in the formation water. The amount of CO_2 ultimately dissolved in water is affected by several factors including temperature and pressure within the reservoir, salinity of the reservoir water and reservoir heterogeneity and geometry.

The pressure/temperature characteristics of the reservoir are two of the primary factors in determining CO_2 dissolution. The amount of CO_2 that can dissolve in fresh water under ideal conditions will increase with additional pressure and decrease with additional temperature, **Figure 19**. Despite working against each other with depth, the effect on CO_2 solubility of pressure is stronger than that of temperature, resulting in an overall increase in CO_2 solubility with depth.

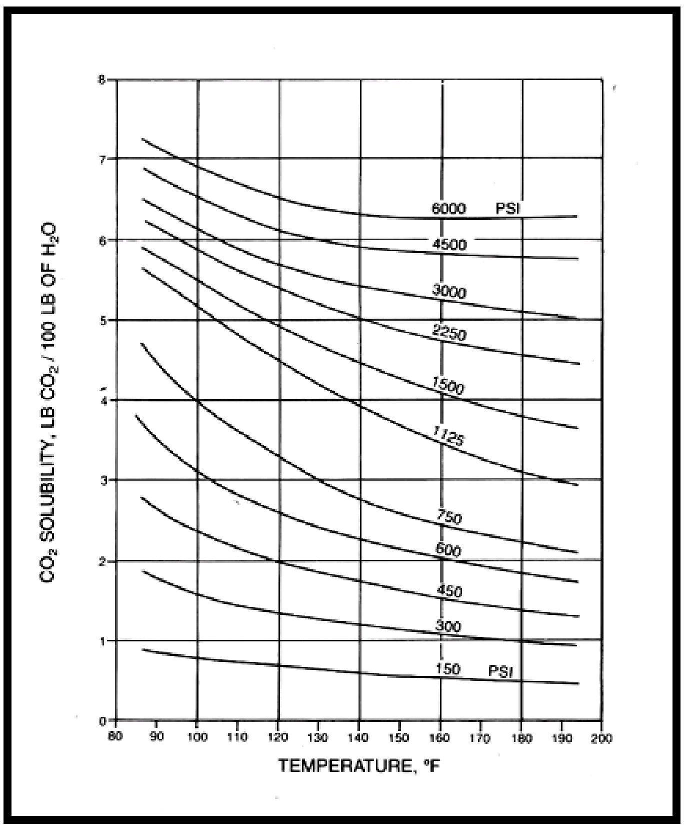

Figure 19: Effect of Temperature and Pressure on CO_2 Solubility [18]

[18] Perkins E (2003) Fundamental geochemical processes between CO_2, water, and minerals. Alberta Innovates–Technology Futures

In addition to temperature and pressure, the composition of the reservoir water also plays an important role in determining how much CO_2 will dissolve. The more dissolved species, especially carbonate species, present in the water (i.e., higher salinity), the less room there is for additional CO_2 to dissolve, **Figure 20.**

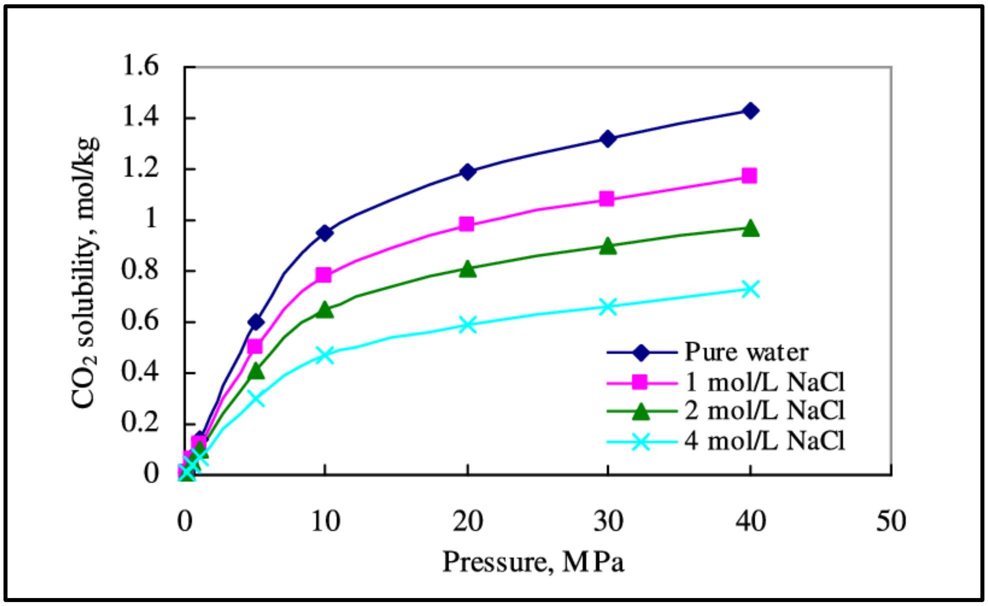

Figure 20: Effect of Salinity on CO_2 Solubility [19]

Under ideal conditions, all the CO_2 is in contact with pristine reservoir water, and all the CO_2 has the potential of being dissolved with time. However, this process is substantially slowed by the geometry of the CO_2 plume. As CO_2 is injected into the reservoir, the water saturation within the plume is at irreducible conditions close to the injection site and increases outward towards the edge of the plume. Therefore, the rate of dissolution is very low close to the injection site and increases outward. In addition, as the CO_2 along the plume edge dissolves into the reservoir water, the water in the immediate vicinity of the plume becomes saturated with CO_2, and dissolution stops until the plume contacts additional unsaturated reservoir brine. Consequently, the geometry and lithologic heterogeneity within the reservoir rock play a very important role in determining how much CO_2 will ultimately be dissolved in the reservoir water.

[19] Wang, Huan & Liao, X. & Zhao, Xiaoliang. (2014). The Influence of CO_2 Solubility in Reservoir Water on CO_2 Flooding and Storage of CO2 Injection into a Water Flooded Low Permeability Reservoir. Energy Sources. 36.

The presence of shale interbeds within the reservoir can serve to slow the plume's ascent (due to buoyancy), allowing more time for dissolution to occur. Shale interbeds also force the CO_2 plume to migrate laterally along the contacts of the shale beds, thereby increasing the plume's surface area and contact with the reservoir water. Both effects can have a strong influence on the rate of dissolution and on the ultimate amount of CO_2 stored in reservoir brine.

Once CO_2 is dissolved in the reservoir brine, density differences within the reservoir water may cause density inversion. Density inversion is a process where the reservoir water in contact with the plume becomes saturated with CO_2, creating a slightly denser fluid than the reservoir brine. The denser CO_2-rich water then begins to sink towards the bottom of the reservoir allowing unsaturated water to encounter the CO_2 plume, encouraging additional dissolution. This process is slow and may require several thousand years and large volumes of CO_2 injection.

Solubility trapping was implemented in the model, and the general Henry's law was applied to compute gas solubility in the aqueous phase.[20] The gas solubility from Henry's law is defined by **Equation 2** below.

Equation 2

$$\mathbf{f}_{\mathbf{CO_2,g}} = \mathbf{f}_{\mathbf{CO_2,w}} = \mathbf{y}_{\mathbf{CO_2,w}} \cdot \mathbf{H}_{\mathbf{CO_2}} \qquad (2)$$

Where:

$f_{CO2,g}$ is fugacity of CO_2 in gas phase

$f_{CO2,w}$ is fugacity of CO_2 in aqueous phase

$Y_{CO2,w}$ is mole fraction of CO_2 in water

H_{CO2} is Henry's constant

[20] Harvey, A.H., "Semiempirical Correlation for Henry's Constants over Large Temperature Ranges", AIChE Journal, Vol. 42, (May 1996), pp. 1491-1494.

Henry's constant (H_{CO2}) is a function of pressure, temperature, and water salinity, which must be input in addition to basic water properties (density, compressibility, and viscosity). Harvey (1996) published correlations to determine Henry's constants for many gaseous components including CO_2, N_2, H_2S and CH_4.[20] These correlations have been implemented in *GEM,* and the Henry's constant is calculated internally in the simulation model.

The second CO_2 storage mechanism is relative permeability hysteresis trapping. Stated simply, hysteresis is primarily an imbalance phenomenon. While this definition may be applied to any number of observations, perhaps the simplest is the process of wetting a sponge and attempting (unsuccessfully) to wring all the water from the sponge. Even after squeezing, the sponge will retain a percentage of water within its pore network. Theoretically, hysteresis trapping occurs because drainage (decreasing wetting phase saturation) and imbibition (increasing wetting phase saturation) gas relative permeability curves vary (for this non-wetting phase). **Figure 21** depicts an idealized pair of drainage and imbibition curves for a gas phase plotted against the gas saturation. Note that the drainage curve (1 to 2) lies above the imbibition curve (2 to 3) and that the imbibition curve has a critical saturation greater than that of the drainage curve (Sgcri > Sgcr). If the primary drainage curve is reversed at position 4 by water encroachment into a CO_2-rich plume, the depicted scanning curve (4 to 5) is the result, which effectively shifts the critical gas saturation to a higher value (Sgcrt > Sgcr).

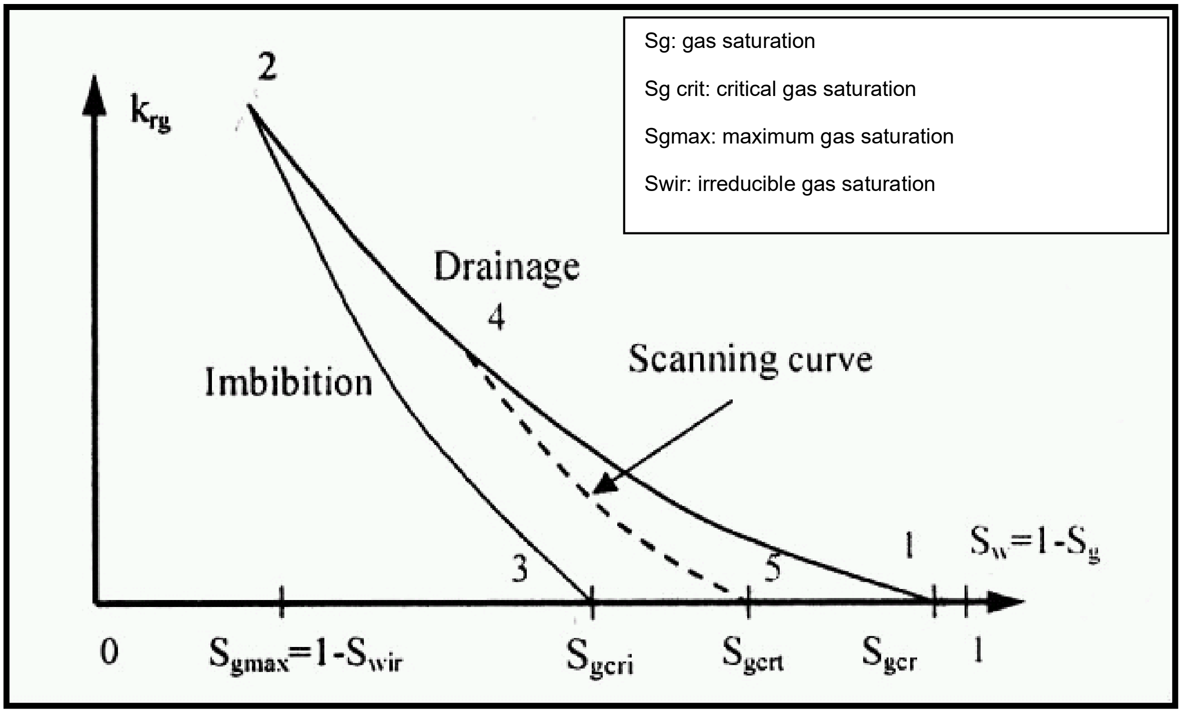

Figure 21: Relative Permeability Hysteresis (after Mo and Akervoll, 2005)[21]

Sequestration through relative permeability hysteresis is primarily a post-injection phenomenon. Witnessed and studied as a side effect of the Water-Alternating-Gas (WAG) enhanced oil recovery (EOR) methodology, this process was shown to result in trapped gas saturations on the order of 20 to 25 percent by pore volume for the South Cowden (Permian Basin, Texas) CO_2-EOR flood.[22] During sequestration of CO_2, this process occurs when water encroaches upon the CO_2 plume. Because continuous CO_2 injection typically overpowers natural water flow, the impact of hysteresis will occur after injection ceases and natural saline water flow becomes the dominant flow mechanism in the reservoir. At this point, drainage-imbibition hysteresis will occur along with a shift in the formation's characteristic relative permeability, resulting in a larger retention of supercritical CO_2 within the pore space. At the head of the plume, drainage will be predominant as water drains away from the rising (buoyant) CO_2. At the bottom of the

[21] S. Mo, I. Akervoll, 2005: Modeling Long-Term CO_2 Storage in Aquifer with a Black-Oil Reservoir Simulator, SPE 93951, SPE/EPA/DOE Exploration and Production Environmental Conference, Galveston, Texas USA, 7-9 March 2005

[22] Wegener, D.C., and K.J. Harpole. "Determination of Relative Permeability and Trapped Gas Saturation for Predictions of WAG Performance in the South Cowden CO2 Flood." Paper presented at the SPE/DOE Improved Oil Recovery Symposium, Tulsa, Oklahoma, April 1996.

plume, imbibition is prevalent as water imbibes behind the migrating plume. These processes will effectively halt CO_2 migration.

The residual CO_2 saturation due to hysteresis depends on the initial gas saturation at the start of the imbibition process. The relationship between the initial CO_2 saturation and the residual saturation is observed to experience a parabola shape that can be fit with a quadratic equation.[23] Studies of residual trapping on sandstone show that when the initial gas saturation is 0.8, the residual CO_2 saturation can be between 0.4 and 0.5 (**Figure 22)**. [24,25]

Since no direct reservoir data or laboratory studies were available, the maximum residual gas saturation in the model was set to 0.45 as an average value. Relative permeability curves and hysteresis phenomenon will be refined during the history-matching process once actual injection and pressure data become available.

[23] E.J. Spiteri, R. Juanes, M.J. Blunt, F.M. Orr Jr., *A new model of trapping and relative permeability hysteresis for all wettability characteristics*, SPE 96448, SPE Annual Technical Conference and Exhibition, Dallas, TX 2005

[24] B. Niu, A. Al-Menhali, S. Krevor, *A study of residual carbon dioxide trapping in sandstone*, Energy Procedia 63 (2014) 5522-5529

[25] S. Bachu, Drainage and imbibition CO_2/brine relative permeability curves at in situ conditions for sandstone formations in western Canada, Energy Procedia 37 (2013) 4428-4436

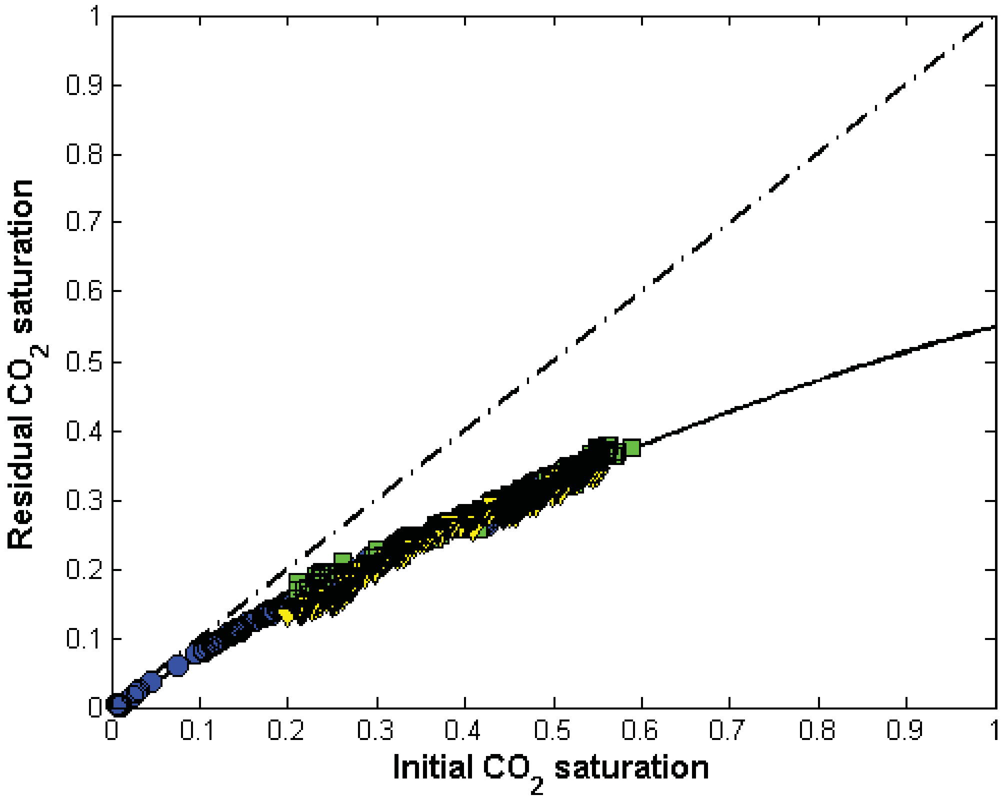

Figure 22: Residual CO_2 Saturation vs Initial CO_2 Saturation (from Niu et. al.)

For the modeling work, the injection stream is assumed to be 100% CO_2. Given the CO_2 composition and saline waters (200,000 mg/L, 4,754 psia and 234°F), we estimate through modeling that approximately 5% of the injected CO_2 volume will be dissolved at the end of the 30-year injection period (**Figure 23**). In addition, we estimate that 12% of the CO_2 will be trapped due to permeability hysteresis at the end of the 30-year injection. **Figure 23** also highlights the fact that the CO_2 stays in the supercritical state over the full course of the injection and post-injection periods. It should also be noted that supercritical phase CO_2 decreases over time, especially after injection ceases, because of continuous CO_2 dissolution in the brine.

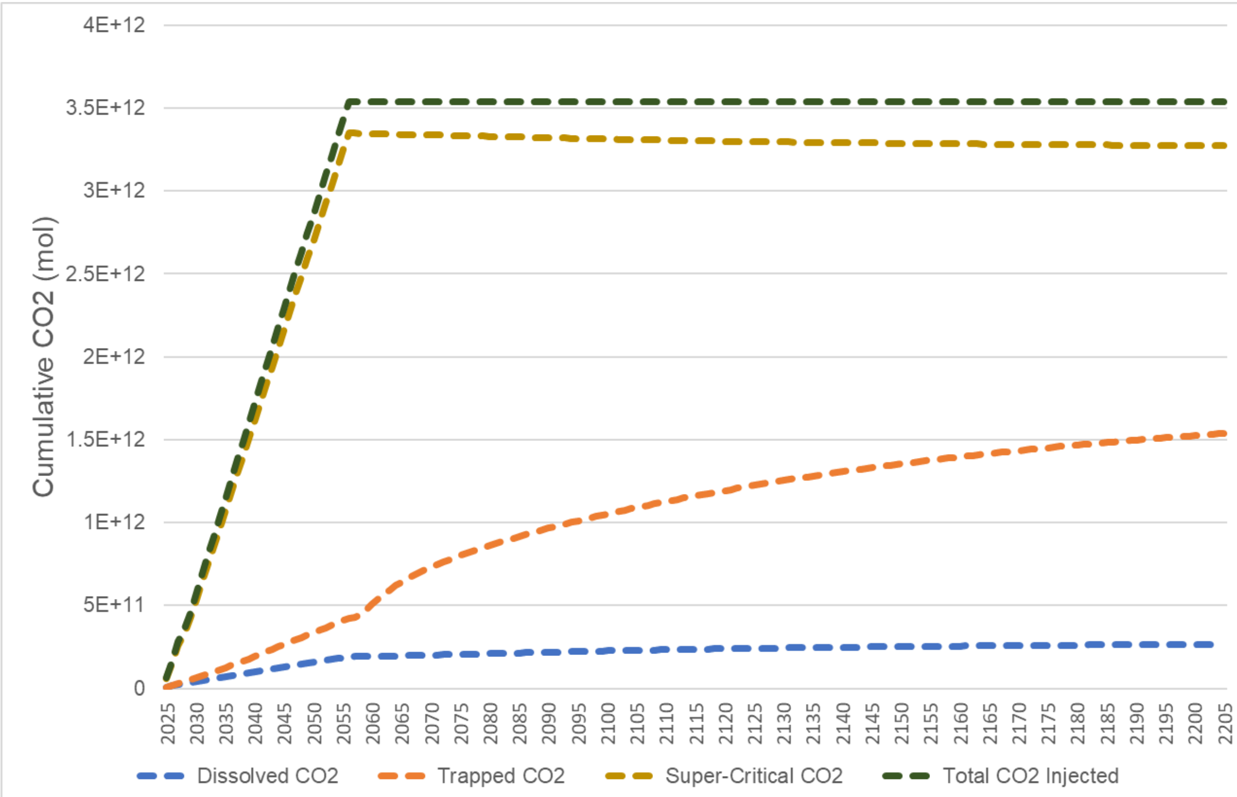

Figure 23: CO_2 Dissolution and Trapping Over Injection and Monitoring Period

After a total of 150 years post-injection, it is estimated that 8% of the injected CO_2 will be dissolved (**Figure 23**). The brines that have mixed with the CO_2 will become dense due to the transfer of some CO_2 mass from the CO_2 plume to the aqueous (water) phase during dissolution and will likely settle toward the bottom of the formation whereupon those brines without CO_2 will rise and encourage new mixing (density inversion) and dissolution. This settling process will occur over time and will be in the general direction of natural groundwater movement. In the unlikely event that direct vertical movement should occur, the Mooringsport seal that lies at the base of the Paluxy formation will provide ample lower confinement, ensuring that the brine and CO_2 stay within the Paluxy formation. In addition, after 150 years post-injection, it is estimated that 43% of the injected CO_2 will be trapped due to permeability hysteresis.

A.4 AoR Delineation Based on Model Results

A.4.a Determination of Pressure Threshold Front

The determination of the pressure front is based on existing standard practices for other well classes in the UIC Program and involves calculation of a threshold reservoir pressure as described in the "UIC Program Class VI Well Area of Review Evaluation and Corrective Action Guidance". The value of the threshold reservoir pressure that defines the pressure front may be calculated based on static pressure within the injection zone and the lowermost USDW, as well as the elevations of both zones by determining the pressure within the injection zone that is great enough to force fluids from the injection zone through a hypothetical open conduit into any overlying USDW (United States Environmental Protection Agency, 2013).[26]

At a minimum, EPA recommends that all wells be monitored for pressure changes monthly during the injection phase. Monitoring frequency may need to be increased if the results of monitoring indicate pressure increases greater than modeling predictions or fluid leakage.

The pressure based AoR is defined by the pore pressure buildup $\Delta(P_{i,f})$ isoline (**Equation 3)** of the following magnitude within which it can cause vertical flow from the injection zone into the USDW. This pressure front methodology is applicable to any Class VI injection well for which, prior to injection, the injection zone is not over pressured compared to the lowermost USDW (refer to **Section 2.1.6** of the ***Computational Model*** regarding the pressure gradient in the Paluxy formation).

[26] EPA (U.S. Environmental Protection Agency). 2013. Geologic Sequestration of Carbon Dioxide, Draft Underground Injection Control (UIC) Program Class VI Well Area of Review Evaluation and Corrective Action Guidance for Owners and Operators. EPA 816-R-13-005, Washington, D.C.

Equation 3

$$\Delta P_{i,f} = P_u + \rho_i g(z_u - z_i) - P_i \qquad (3)$$

Where,

$\Delta P_{i,f}$ = minimum pressure buildup within the injection zone necessary to cause vertical flow from the injection interval into the USDW, MPa

P_i = initial pressure in the injection zone, MPa

P_u = pressure within the lowermost USDW, MPa

ρ_i = fluid density in the injection zone, kg/m3

g = acceleration due to gravity, 9.8 m/s2

z_i = injection depth, m

z_u = depth of the lowermost USDW, m

The lowermost USDW is in the Chickasawhay formation, with an average depth of 1,700 ft. The pressure increase necessary to cause vertical flow was computed to be 166 psi, using the following parameters (**Table 10)**:

Table 10: Parameters Used to Calculate Pressure Threshold

Parameter	Value	
	(Metric Units)	(English Units)
USDW depth, m or ft	518	1,700
Initial fluid pressure in the USDW, MPa or psia	5.10	740
Top of injection zone elevation, m or ft	3,088	10,131
Initial fluid pressure in the injection zone, MPa or psia	32.34	4,690
Fluid density in the injection zone, kg/m3 or lb/ft^3	1,127	70.35

A.4.b AoR Delineation

The AoR is based on the *Maximum Extent of the Separate-phase Plume and/or Pressure-front* methodology over the lifetime of the project, as detailed in the "UIC Program Class VI Well Area of Review Evaluation and Corrective Action Guidance" (USEPA, 2013)[26]. In **Figure 24**, the blue dotted line shows the extent of the pressure front (area over the computed threshold pressure of 166 psi) one year following the end of injection, and the red dotted line shows the extent of the CO_2 saturation plume 20 years post injection. Three years after the end of injection, the entire pressure front dissipates below the critical pressure value of 166 psi. The figure shows that the CO_2 plume at the end of 20 years post-injection overtakes the maximum extent of the pressure front in most areas.

The purple solid line delineates the AoR based on the maximum extent of both the pressure front and CO_2 plume.

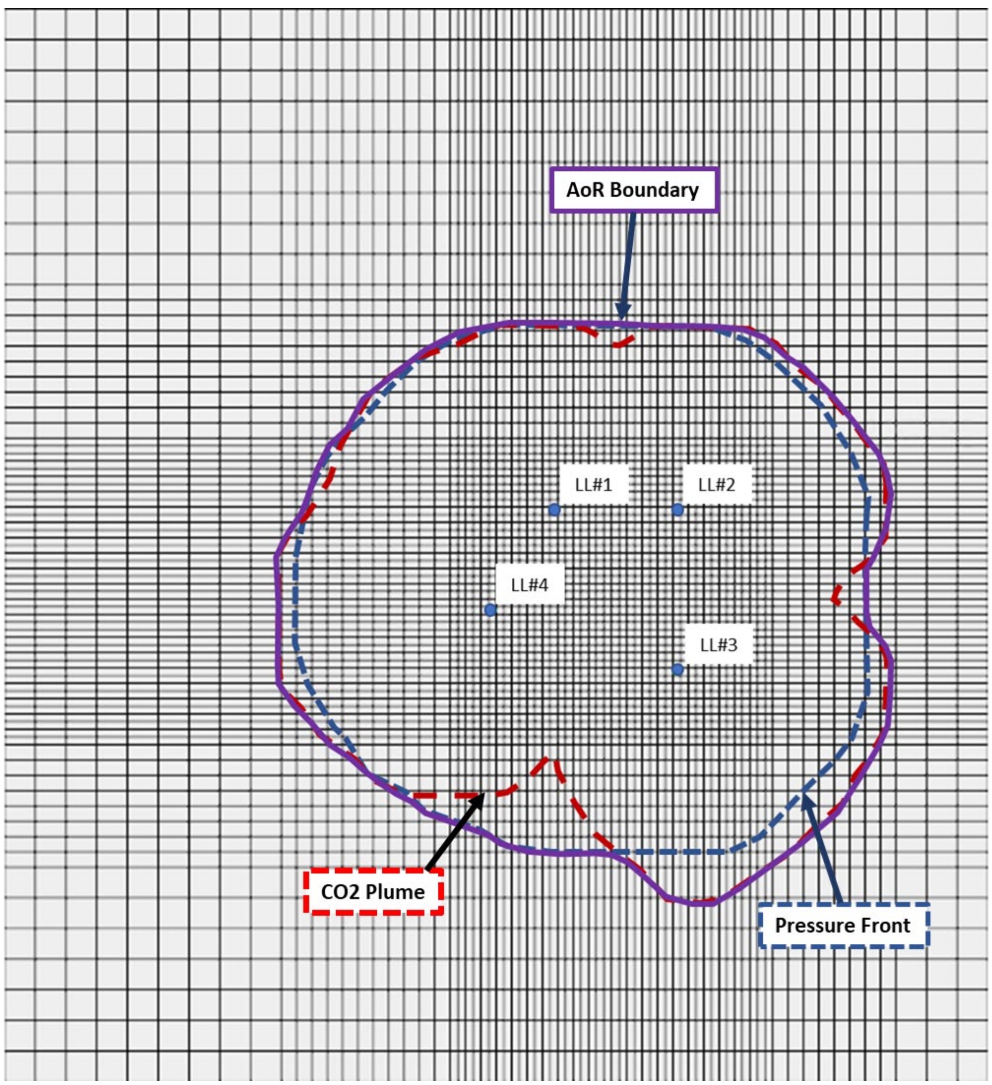

Figure 24: Maximum Extent of Pressure Front, CO_2 Plume Extent 20 Years Post-Injection, and Longleaf CCS Hub AoR Boundary

As illustrated on **Figure 17**, the CO_2 saturation plume has stabilized 20 years after the end of injection. While it is still mobile, its migration is steady and predictable. Thus, the AoR is delineated 20 years after the end of injection. At this stage, the CO_2 saturation plume extends approximately 5.9 miles east-to-west, 5.5 miles north-to-south and covers an area of approximately 32.5 square miles (**Figure 25)**.

The AoR, as shown in the model, reaches the monitoring wells IOB#1 and UOB#1 to the north and IOB#2 and UOB#2 to the northeast where it ceases migration beyond this extent. Monitoring wells IOB#3 to the southeast and IOB#5 to the northwest are positioned beyond the extent of the AoR. While the CO_2 plume has reached three of the five in-zone monitoring wells (IOB#1, IOB#2, and IOB#4) 20 years post-injection, the wells will still serve as viable monitoring wells. Vertical seismic profiles (VSP) will be used for monitoring the CO_2 plume during injection, as outlined in **Section E.5.1** of the ***Testing and Monitoring Plan***. The efficacy of the VSPs is a radius of approximately 1 mi, which includes the extent of the CO_2 plume 20 years post-injection.

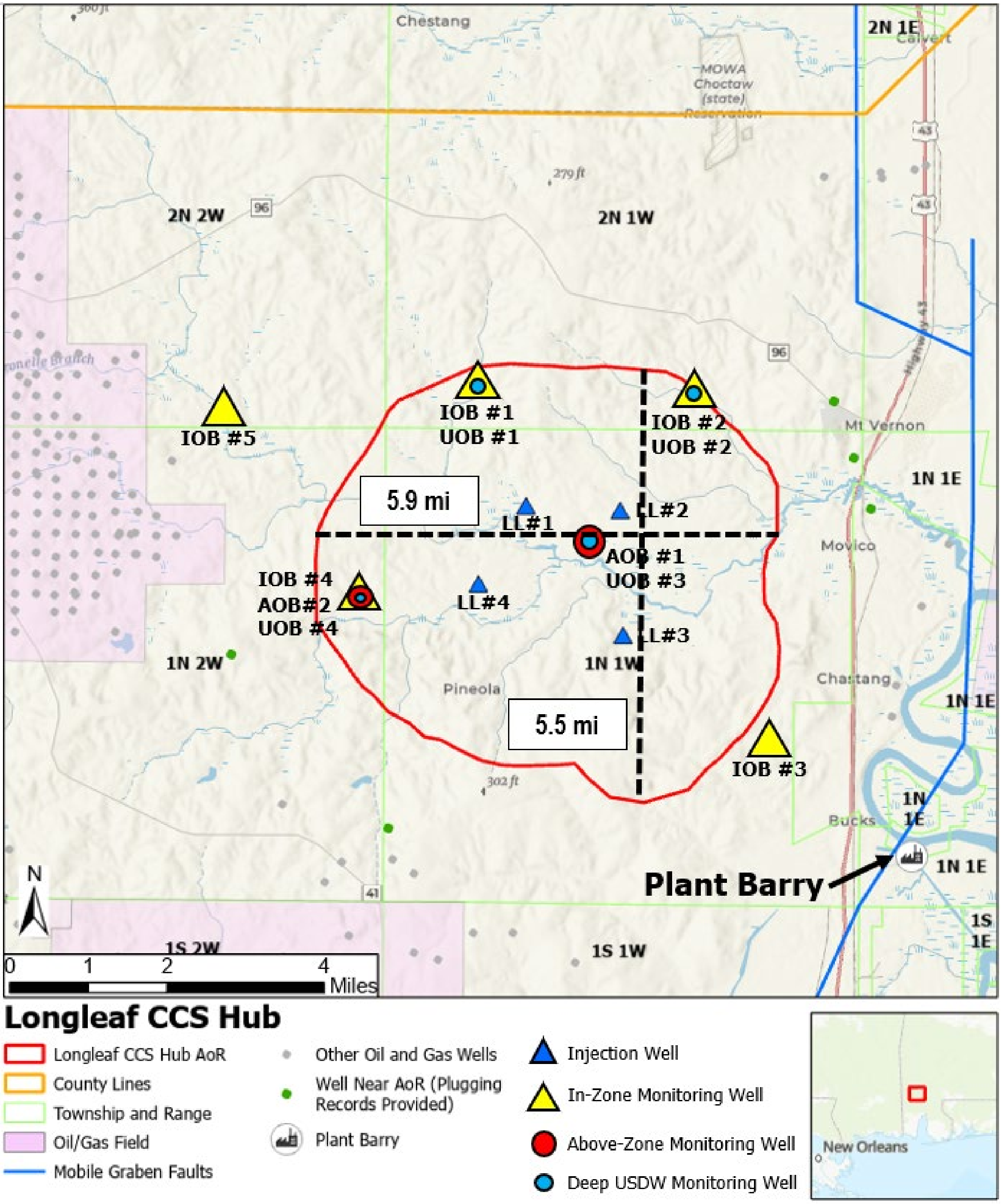

Figure 25: Area of Review at 20 Years after the End of Injection

B. Identifying Artificial Penetrations and Performing Corrective Action

B.1 Corrective Action Rule Requirements

This Section addresses corrective action requirements within the AoR from 40 CFR 146.84(c) – (e).

B.2 Identifying Artificial Penetrations within the AoR

B.2.a Wells Penetrating the Confining Zone

There are no existing wellbores that penetrate the primary confining unit within the AoR. Information on the nearest wellbores to the AoR is provided in **Table 11**. All injection and monitoring wells will be drilled in compliance with 40 CFR 146 as outlined in the ***Injection Well Construction Plan*** and State Oil and Gas Board of Alabama regulatory guidelines for monitoring wells.

Table 11: Legacy Wellbores near the AoR

Well Name	API	Latitude	Longitude	Spud Date	TD (ft.)
O.P. Turner #31-4	0109720209	31.01112	-88.12350	5/20/1982	18,614
St. of AL & AL St. Hospitals #1	0109719966	31.08051	-88.02464	7/1/1963	12,521
AL State Hospitals "B" #1	0109719528	31.09098	-88.02893	8/4/1951	11,014
Tensaw Land & Timber Co. #1	0109720114	31.07121	-88.02060	7/14/1977	18,020
Lambert Heirs #1	0109720030	31.04317	-88.15742	2/3/1975	11,960

B.3 Assessing Identified Abandoned Wells

The identified abandoned wellbores lie outside the AoR and were all plugged and abandoned in compliance with Alabama Oil and Gas Board (AOGB) requirements, respectively. Available drilling and completion records, plugging records, and wellbore diagrams for these five wells are provided in **Appendix A** to this plan. Three of the five wells, while originally plugged in compliance with AOGB requirements, are plugged insufficiently to prevent migration of CO_2 above the primary confining unit, the Tuscaloosa Marine Shale. They are:

- Tensaw Land & Timber Co. #1 (API: 01-097-20114)

- State of Alabama & Alabama State Hospitals #1 (API: 01-097-19966)
- Alabama State Hospitals “B” #1 (API: 01-097-19528)

As such, a “Corrective Action Response Boundary” has been defined between the AoR and these 5 wells, **Figure 26.** If CO_2 migrates beyond this boundary, it will trigger the corrective action plan described below in **Section B.4. *Performing Corrective Action on Legacy Wellbores.***

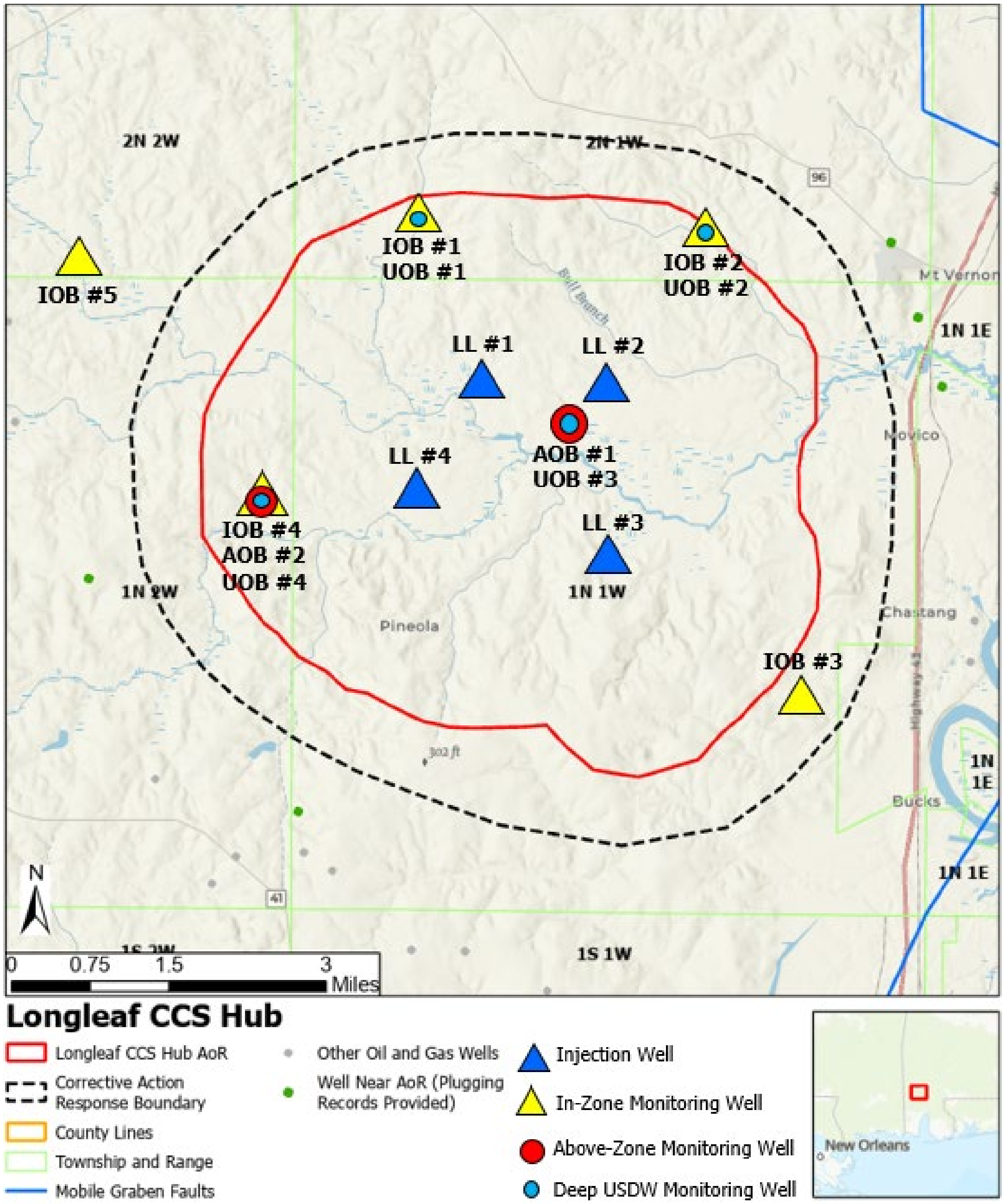

Figure 26: Map of Corrective Action Response Boundary in Relation to AoR and Nearest Legacy Wellbores.

B.4 Performing Corrective Action on Legacy Wellbores

B.4.a Plan for Site Access

If corrective action is required, Longleaf CCS, LLC will engage with the affected landowners to inform them of the necessary actions. Landowners will be compensated for any damages to the surface resulting from corrective action operations.

B.4.b Corrective Action Operations Procedure

If CO_2 migrates beyond the Corrective Action Response Boundary toward any of the three insufficiently plugged wellbores listed in **Section B.3**, the corrective action plan will be triggered, and the following steps will be taken:

- Locate well and dig out dirt surrounding cut casing.
- Rig up on location of well.
- Cut out steel plate and connect to cut surface casing.
- Drill out cement plugs.
- Tag well at TD.
- Fill long string casing with cement from TD to surface.
    - ✓ The interval corresponding to the injection zone will be plugged with CO_2-resistant cement.

C. AoR Reevaluation

C.1 AoR Reevaluation Cycle

Longleaf CCS, LLC will review the AoR annually during the injection phase and once every two years during the post-injection phases to ensure the initial model predictions are adequate for predicting the extent of the CO_2 plume and pressure front. Incorporating new monitoring data collected as part of activities outlined in the ***Testing and Monitoring Plan*** annually will allow Longleaf CCS, LLC to base its reevaluation of the AoR on the consistency of the modeled extent of the plume and pressure front with actual project data and, if needed, propose re-delineations to the AoR.

Monitoring and operational data include data from the two injection wells, in-zone monitoring wells, above-zone monitoring wells, deep USDW monitoring wells, and shallow groundwater monitoring wells. Monitoring activities to be conducted are described in more detail in the ***Testing and Monitoring Plan***. Project data from the two injection wells and all monitoring wells will be compared with the predicted CO_2 plume migration to ensure the two are consistent, specifically conducting the following activities:

- Using pulsed neutron and temperature logs, flow profile surveys, and fluid sampling to locate and track the movement of the CO_2 plume in the injection formation. As detailed in the ***Testing and Monitoring Plan***, pulsed neutron and temperature logs and flow profile surveys will be conducted annually during the injection period. Fluid sampling will occur annually at in-zone monitoring wells until it is observed that the CO_2 plume has reached that well.

- Verifying operating injection rates and pressures are consistent with the modeling inputs.

- Evaluating pressure data from the annulus, and above-zone monitoring wells, as detailed in the ***Testing and Monitoring Plan***, to ensure no evidence of CO_2 leakage.

- Any new or updated geologic data that has been acquired since the last modeling effort will be evaluated in the model inputs/assumptions to determine if the AoR requires reevaluation.

- Reviewing groundwater monitoring data to verify there is no evidence of leakage of CO_2 or formation fluids that represent an endangerment to any USDWs.

All the monitoring and operational data will be compared with the results of the initial computational modeling used for AoR delineation. Statistical methods will be employed to correlate the data and confirm the model's ability to accurately represent the Longleaf CCS Hub.

Longleaf CCS, LLC will prepare a report demonstrating that no reevaluation of the AoR delineation is necessary if the information reviewed is not significantly different from the most recent modeling assumptions and predictions about the migration extent of the plume and pressure front. This report will be submitted to EPA to demonstrate that no amendment of the AoR and Corrective Action Plan is needed (40 CFR 146.84(e)(4)).

If it is found that the geologic characterization or behavior of the plume or pressure front is significantly different from the most recent model's predictions, and that the actual plume or pressure front extends beyond what is modeled, Longleaf CCS, LLC will re-delineate the AoR. If necessary, re-delineation will include the following steps:

- Calibrating the model with new site characterization, operational, or monitoring data (pressures and fluid saturations).
- Performing a new AoR delineation with the same methods described in the Computational Modeling portion of this plan.
- Identify any new wells that penetrate the confining zone within the new AoR and provide a description of each well's type, construction, date drilled, location, depth, and records of plugging and/or completion.
- Perform corrective action on all new wells that penetrate the confining zone within the newly defined AoR to ensure that they will not act in such a way as to promote the migration of CO_2 or other fluids that endanger any USDWs.

If the reevaluation process results in the re-delineation of the AoR, Longleaf CCS, LLC will amend this Plan and provide details on the decision to update the AoR delineation and the data evaluated used to make the decision. The amended AoR and Corrective Action Plan will be submitted to EPA for approval (40 CFR 146.84(e)(4)).

C.2 Triggers for AoR Reevaluations Prior to the Next Scheduled Reevaluation

As stated above, Longleaf CCS, LLC plans to review the AoR every year during the injection phase and every two years during the post-injection phase. As detailed in the ***Testing and Monitoring Plan***, monitoring and operational data are reviewed more frequently and could suggest that the actual extent and movement of the plume or pressure front have deviated significantly from the modeled predictions. Therefore, it may be necessary to initiate a reevaluation of the AoR prior to the next scheduled reevaluation period. The following is a list of unexpected changes in the quantitative parameters that could trigger reevaluation of the AoR.

- **Pressure:** Unexpected changes in injection pressure, reservoir pressure or above-zone pressure that are of concern.

- **Temperature:** Unexpected changes in temperature that are of concern.

- **CO_2 Saturation:** Unexpected changes in CO_2 saturation that indicate the movement of CO_2 out of the injection formation and above the confining zone. If this change is due to well integrity, no AoR reevaluation will be triggered, and the well integrity issue will be addressed.

- **Deep Groundwater Sampling:** Unexpected changes in groundwater geochemical and physical parameters that may indicate movement of CO_2 and formation fluids from the injection zone and into formations above the confining zone.

Other events that may trigger an AoR reevaluation include the following:

- Seismic event greater than M3.4 within 8 miles of the injection wells, if it is likely that the actual plume or pressure front extends beyond what is modeled.

- Additional zones are permitted and used for injection of CO_2.

- New site characterization data become available that significantly modifies the extent of the plume or pressure front beyond what is predicted by the initial model. This can include the identification of a previously unknown fault or fracture in the confining or injection zones.

Longleaf CCS, LLC will report any such events to the UIC Program Director to determine if an AoR reevaluation is required. If an unscheduled reevaluation is triggered, Longleaf CCS, LLC will perform the steps described at the beginning of this section of this Plan.

Longleaf CCS Hub

Longleaf CCS, LLC

Emergency and Remedial Response Plan

40 CFR 146.94 (a)

Facility Information

Facility Name: Longleaf CCS Hub

Facility Contact: Longleaf CCS, LLC
14302 FNB Parkway
Omaha, NE 68154

Well Locations: Mobile County, Alabama
LL#1: Latitude: 31.071303° N
Longitude: -88.094703° W
LL#2: Latitude: 31.070774° N
Longitude: -88.074523° W
LL#3: Latitude: 31.0447129° N
Longitude: -88.0736318° W
LL#4: Latitude: 31.0569516° N
Longitude: -88.1047433° W

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List of Acronyms/Abbreviations

AoR	Area of Review
CCS	Carbon capture and storage
CO_2	Carbon dioxide
CMG	Computer Modelling Group
DOE	Department of Energy
DAS	Distributed Acoustic Sensing
DTS	Distributed Temperature Sensing
EPA	Environmental Protection Agency
ERRP	Emergency and Remedial Response
ft	Feet
LL	Longleaf
MIT	Mechanical Integrity Test
MMcf/d	Million cubic feet/day
mg/l	Milligrams per liter
mt	Metric tons
Mt	Millions of metric tons
mt/d	Metric tons per day
mt/y	Metric tons per day
MT/y	Millions of metric tons per year
PISC	Post-Injection Site Care
PNC	Pulsed Neutron Capture Log
psi	Pounds per square inch
psi/ft	Pounds per square inch per foot
SS	Sub-Sea
TVD	True Vertical Depth
UIC	Underground Injection Control
USDW	Underground Source of Drinking Water

A. Introduction

The purpose of this plan is to meet the requirements of 40 CFR 146.94 under the UIC Class VI Permit Guidelines. This ***Emergency and Remedial Response Plan*** (***ERRP***) covers the four proposed injection wells at the Longleaf CCS Hub in Mobile County, Alabama: LL#1, LL#2, LL#3, and LL#4. The ***ERRP*** outlines the actions that Longleaf CCS, LLC will take to address the unexpected movement of injection fluid or formation fluid in such a way as to endanger an underground source of drinking water (USDW) during the construction, operation, and post-injection site care (PISC) periods.

B. Local Resources and Infrastructure

The Longleaf CCS Hub AoR as described in the ***Area of Review and Corrective Action Plan*** covers an approximately 26 mi^2 area in northern Mobile County, as illustrated in **Figure 1** below. Overall, the land surface is sparsely populated and rural. Resources in the vicinity of the Longleaf CCS Hub that may be affected as a result of an emergency event in the project area include:

- **Citronelle Formation (Plio-Pleistocene)** – shallowest USDW source
- **Miocene series** – primary water source in northern Mobile County
- **Chickasawhay Formation (Upper Oligocene)** – the lowermost potential USDW
- **Surface bodies of water** – Cedar Creek, North Fork Cedar Creek, Bush Coon Creek, Indian Grave Creek, Conrad Creek, Grady Hall Creek, Bull Branch, Broad Branch, Boggy Branch, Spring Branch, and one small pond (unnamed).

There is limited existing infrastructure within the Longleaf CCS Hub project area. All land parcels within the Longleaf CCS Hub are classified as residential, with some containing residential buildings, while the rest are vacant. Other infrastructure within the project AoR are domestic water supply wells. The location of land parcels with residential buildings, domestic water supply wells, and vacant parcels are illustrated in **Figure 1**, with the Longleaf CCS Hub AoR shown for reference.

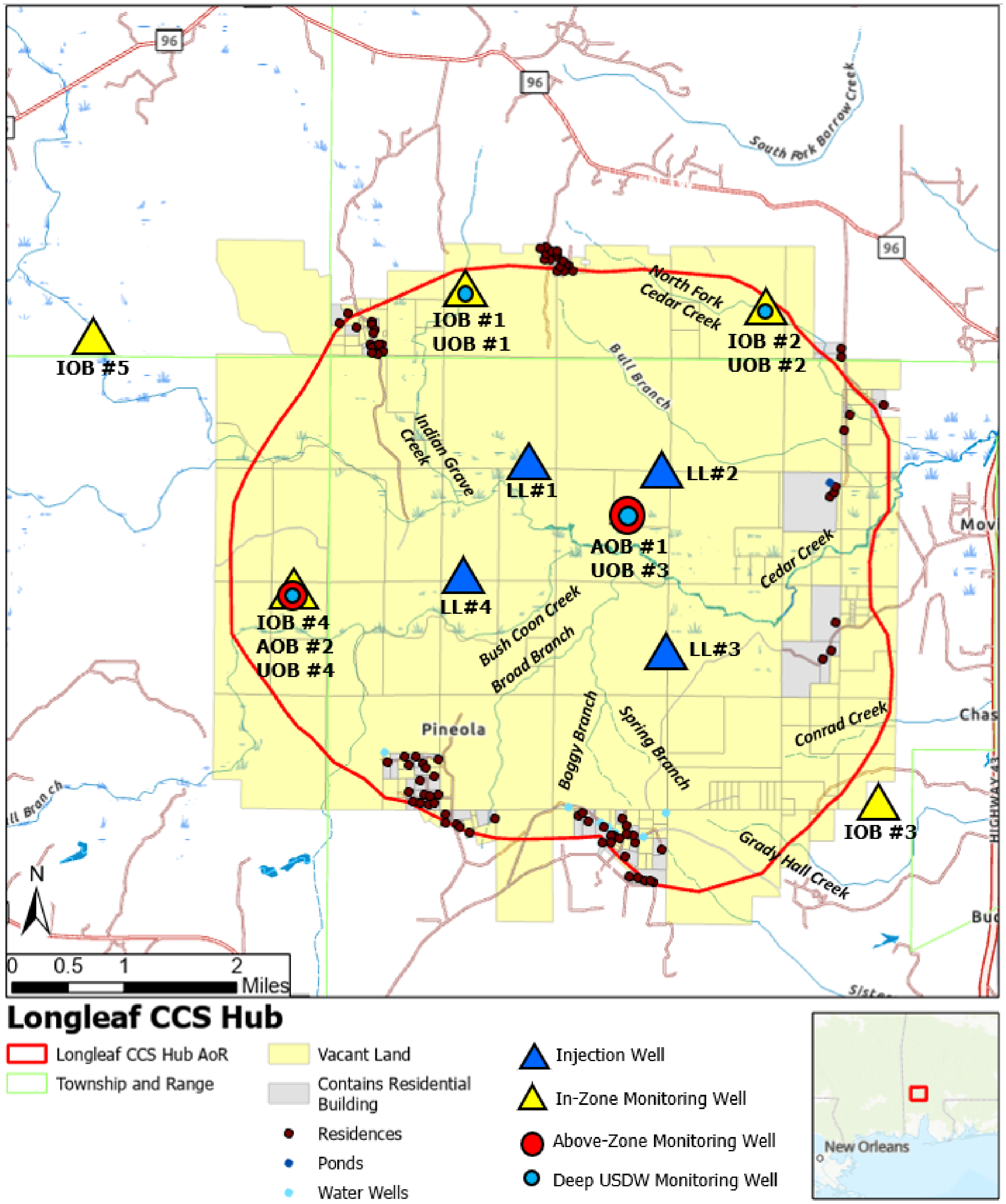

Figure 1. Map of the Site Resources and Infrastructure.

C. Potential Risk Scenarios

Several scenarios could trigger an emergency response. Events that would trigger emergency responses include incidents that could cause personal injury, that could lead to contamination of the USDW, or that could result in property damage. These events may occur during the construction, injection, or post-injection site care period. Possible major or moderate events requiring an emergency response for each stage of project development at the Longleaf CCS are outlined in **Table 1**.

Table 1. Risk Scenario Matrix for Longleaf CCS Hub

Risk Scenario	Construction Period	Injection Period	Post-Injection Site Care Period	Severity Range	Appendix A Item Number
Fluid communication between formations while drilling	x			Moderate to Major	1-3
Fluid leakage into USDW or ground surface through wellbore (injection, monitoring, P&A, or other), surface equipment failure, faults, fractures, or confining zone failure		x	x	Minor to Major	4-17
External impact to project wellheads or pipelines		x	x	Moderate to Major	20-22
Loss of mechanical integrity (injection or monitoring well)	x	x	x	Minor to Major	4-7
Migration of CO_2 outside of defined AoR		x	x	Minor to Major	18-19
Injection or monitoring equipment failure/malfunction		x	x	Minor to Moderate	23-26
Induced seismicity		x	x	Minor to Major	27-28
Natural disaster (hurricane, earthquake, tornado, lightning, flood)		x	x	Minor to Major	29-30
Accident or unplanned event (e.g., electrical outage causing injection to stop)		x		Minor	31

The risk scenarios outlined in **Table 1** and response actions for these risk scenarios are summarized in ***Appendix A***. The appropriate response will depend on the nature of the emergency and the severity of the event. Emergency severity is categorized into minor, moderate, and major events, as defined in **Table 2**, and the range of severity for each risk scenario in **Table 1** is based on these criteria. A formal risk assessment will be conducted prior to requesting permission to operate, with a formal risk assessment report provided to the UIC Program Director.

Table 2. Degrees of Risk for Emergency Events.

Emergency Severity	Definition
Major Emergency	Event poses immediate substantial risk to human health, resources, or infrastructure. Emergency actions involving local authorities (evacuation or isolation of areas) should be initiated.
Moderate Emergency	Event poses potential serious (or significant) near term risk to human health, resources, or infrastructure if conditions worsen or no response actions taken.
Minor Emergency	Event poses no immediate risk to human health, resources, or infrastructure.

D. Emergency Identification and Response Actions

Steps to identify and characterize the event will be dependent on the specific issue identified and the severity of the event. The following actions will be taken by Longleaf CCS, LLC if, through monitoring activities, there is evidence that a major or moderate emergency has occurred that may pose a risk to a USDW or community infrastructure:

1. Initiate the emergency shutdown plan for the injection well.
2. Take all steps reasonably necessary to identify and characterize the suspected cause of the event.
3. Notify the facility's 24-Hour Emergency Contact of the emergency within 24 hours followed by a contact with the UIC Program Director.
4. 24-Hour Emergency Contact will contact the response personnel listed in the column headed "Response Personnel" in ***Appendix A***, as needed.
5. Implement the applicable portions of the approved ***ERRP***.

Where the phrase "initiate the emergency shutdown plan" is used, the following protocol will be employed: Longleaf CCS, LLC will endeavor to immediately cease injection; however, in some circumstances, Longleaf CCS, LLC will, in consultation with the UIC Program Director, determine whether gradual cessation of injection (using the parameters set forth in ***Appendix A*** of this plan) is appropriate.

The specific potential risk scenarios identified in ***Part C*** and detailed in ***Appendix A*** are conceptual, and the specific response plans may be amended in coordination with the UIC Program Director based on health, safety, and environmental circumstances specific to each event. In the event of an emergency requiring outside assistance, the lead project contact will notify the 24-Hour Emergency Contact identified in ***Appendix B*** of this ***ERRP*** as soon as possible after requesting outside assistance from local emergency responders. Other notifications will be determined based on the type of emergency and notification requirements identified in ***Appendix A***.

E. Response Personnel and Equipment

Site personnel, project personnel, and local authorities will be relied upon to implement this ***ERRP***. The City of Citronelle and the communities of Movico and Mt. Vernon are the closest population centers to the Longleaf CCS Hub. Therefore, both city and county emergency responders (as well as state agencies) may need to be notified in the event of an emergency. Please refer to ***Appendix B*** for an emergency contact list that will be updated annually at a minimum.

Equipment needed in the event of an emergency and remedial response will vary depending on the triggering emergency event and is specified for each potential risk scenario in Appendix A. Response actions (cessation of injection, well shut-in, and evacuation) will generally not require specialized equipment to implement. Where specialized equipment (such as a drilling rig or logging equipment) is required, Longleaf CCS, LLC will be responsible for its procurement.

F. Emergency Communications Plan

In the event of an emergency requiring outside assistance, the lead project contact will notify the 24-Hour Emergency Contact identified in ***Appendix B*** of this ***ERRP*** as soon as possible after requesting outside assistance from local emergency responders.

Longleaf CCS, LLC will communicate to the public about any event that requires an emergency response to ensure that the public understands what happened and whether there are any environmental or safety implications. The amount of information, timing, and communications method(s) will be appropriate to the event, its severity, whether any impacts to drinking water or other environmental resources occurred, any impacts to the surrounding community, and their awareness of the event.

Longleaf CCS, LLC will describe what happened, any impacts to the environment or other local resources, how the event was investigated, what responses were taken, and the status of the response. For responses that occur over the long-term (e.g., ongoing cleanups), Longleaf CCS, LLC will provide periodic updates on the progress of the response action(s).

Longleaf CCS, LLC will also communicate with entities who may need to be informed about or act in response to the event, including local water systems, CO_2 source(s) and pipeline operators, landowners, and Regional Response Teams (as part of the National Response Team).

G. Plan Review

This ***ERRP*** shall be periodically reviewed as follows:

- At least once every five (5) years following its approval by the permitting agency.
- After an area of review (AoR) reevaluation.
- Following any significant changes to the injection process or the injection facility, or an emergency event; and
- At least annually for the Emergency Contact List in ***Appendix B*** of this ***ERRP***.

An amended ***ERRP*** should be submitted to the UIC Program Director within 1 year of an AoR reevaluation, following any significant changes to the facility, or when required by the UIC Program Director. Amendments must be approved by the UIC Program Director and incorporated into the permit and are subject to permit modification requirements. If the review indicates that no amendments to the ***ERRP*** are necessary, Longleaf CCS, LLC will provide the UIC Program Director with the documentation supporting the "no amendment necessary" determination. Updating the Emergency

Contact List and clarifications or corrections are not considered an amendment to the ***ERRP*** and do not require permit modification (40 CFR 144.41).

H. Staff Training and Exercise Procedures

Longleaf CCS, LLC will integrate the ***ERRP*** into its existing operating procedures and training protocols. Periodic training will be provided, not less than annually, to construction personnel, well operators, project safety and environmental personnel, the operations manager, and corporate communications. The training plan will document that the necessary personnel have been trained and possess the required skills to perform their relevant emergency response activities described in the ***ERRP***.

I. Communications with Adjacent Landowners and Emergency Response Personnel

Prior to the start of CO_2 injection operations, Longleaf CCS, LLC will attempt to promptly communicate with landowners living near each injection well site as identified on **Figure 2** to provide information of the nature of the operations, potential risks, and appropriate response approaches under various emergency scenarios. Longleaf CCS, LLC's point of contact for any landowner or stakeholder concerns is listed in **Table 3**.

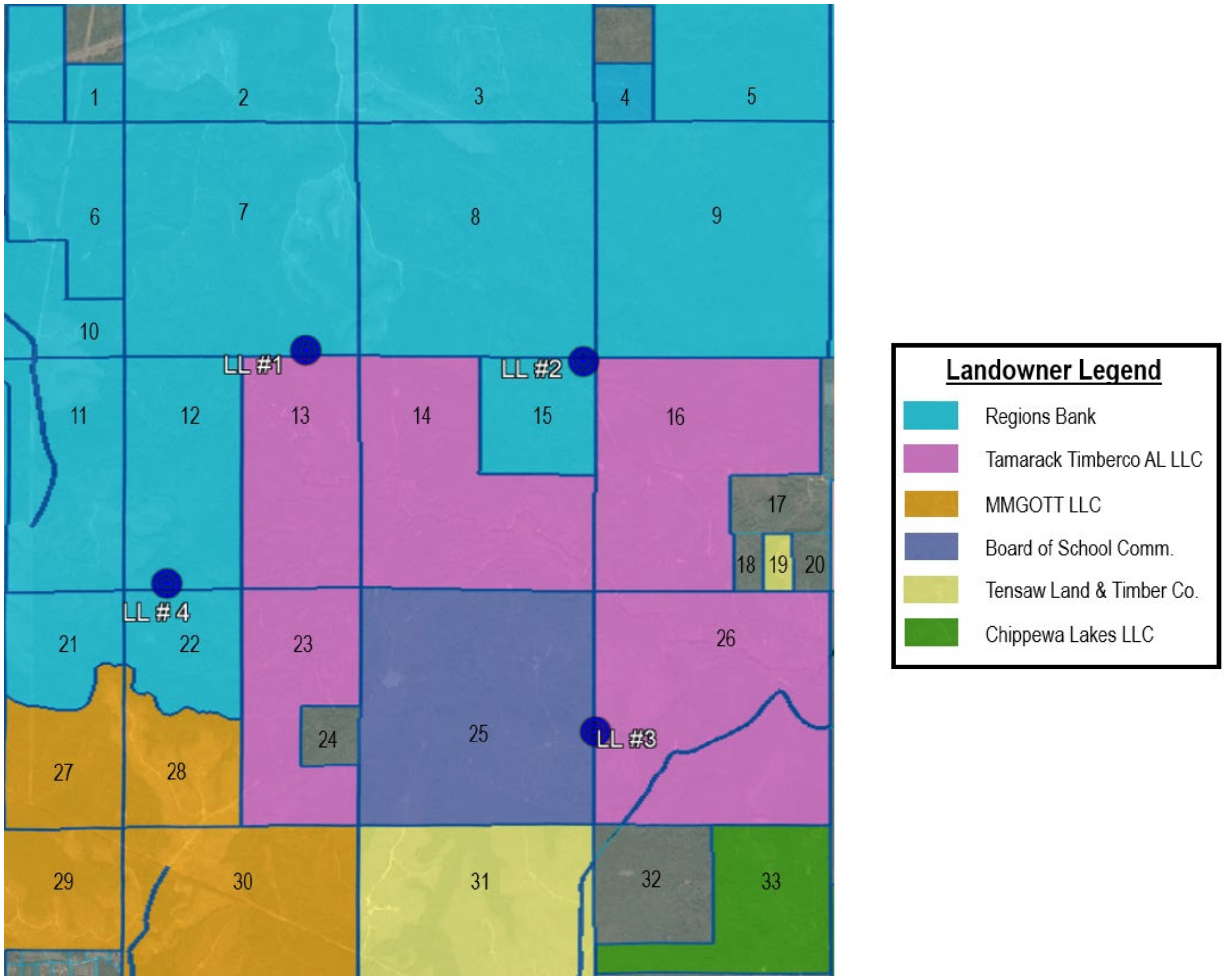

Figure 2. Aerial map provided by Longleaf CCS, LLC identifying the land parcels and ownership around the proposed injection wells. Landowner details are provided in Table 3.

Table 3. Details of the landowners identified by Longleaf CCS, LLC shown in Figure 2.

Tract Number	Parcel ID	S – T – R	Owner Name	Address
1	0209310000017	31-2N-1W	Regions Bank	PO BOX 13519 ARLINGTON TX 76094
2	0209320000005	32-2N-1W	Regions Bank	P O BOX 13475 ARLINGTON TX 76094
3	0208330000007	33-2N-1W	Regions Bank	P O BOX 13475 ARLINGTON TX 76094
4	0208340000003	34-2N-1W	Regions Bank	PO BOX 13519 ARLINGTON TX 76094
5	0208340000001	34-2N-1W	Regions Bank	PO BOX 13519 ARLINGTON TX 76094
6	0903060000002	06-1N-1W	Regions Bank	PO BOX 13519 ARLINGTON TX 76094
7	0903050000001	05-1N-1W	Regions Bank	PO BOX 13519 ARLINGTON TX 76094
8	0902040000001	04-1N-1W	Regions Bank	PO BOX 13519 ARLINGTON TX 76094
9	0902030000001	03-1N-1W	Regions Bank	PO BOX 13519 ARLINGTON TX 76094
10	0903060000002	06-1N-1W	Regions Bank	PO BOX 13519 ARLINGTON TX 76094
11	0903070000001	07-1N-1W	Regions Bank	PO BOX 13519 ARLINGTON TX 76094
12	0903080000002	08-1N-1W	Regions Bank	PO BOX 13519 ARLINGTON TX 76094
13	0903080000001	08-1N-1W	Tamarack Timberco AL LLC	31 INVERNESS CENTER PKWY STE 200 HOOVER AL 35242
14	0902090000002	09-1N-1W	Tamarack Timberco AL LLC	31 INVERNESS CENTER PKWY STE 200 HOOVER AL 35242
15	0902090000001	09-1N-1W	Regions Bank	PO BOX 13519 ARLINGTON TX 76094
16	0902100000001	10-1N-1W	Tamarack Timberco AL LLC	31 INVERNESS CENTER PKWY STE 200 HOOVER AL 35242
17	0902100000002	10-1N-1W	Robert Keith Dickson	509 WESLEY V ST SATSUMA AL 36572
18	0902100000003	10-1N-1W	Matthew Thomas Woolley	235 MAPLE DR

Tract Number	Parcel ID	S – T – R	Owner Name	Address
				NEW HOLLAND PA 17557
19	0902100000004	10-1N-1W	Tensaw Land & Timber Co. Inc.	3511 MONTLIMAR PLAZA DR MOBILE AL 36609
20	0902100000005	10-1N-1W	Crum Elizabeth Skinner & Joseph Boyd Skinner	3325 WARRENTON RD MONTGOMERY AL 36111
21	0904180000001	18-1N-1W	Regions Bank	PO BOX 13519 ARLINGTON TX 76094
22	0904170000002	17-1N-1W	Regions Bank	PO BOX 13519 ARLINGTON TX 76094
23	0904170000001	17-1N-1W	Tamarack Timberco AL LLC	31 INVERNESS CENTER PKWY STE 200 HOOVER AL 35242
24	0904170000003	17-1N-1W	Kenneth A Chastang	640 ANDRY RD MT VERNON AL 36560
25	0905160000001	16-1N-1W	Board of School Commisioners of Mobile County	PO BOX 180069 MOBILE AL 36618
26	0905150000001	15-1N-1W	Tamarack Timberco AL LLC	31 INVERNESS CENTER PKWY STE 200 HOOVER AL 35242
27	0904180000001	18-1N-1W	MMGOTT LLC	PO BOX 1288 MOBILE AL 36633
28	0904170000002	17-1N-1W	MMGOTT LLC	PO BOX 1288 MOBILE AL 36633
29	0904190000001	19-1N-1W	MMGOTT LLC	PO BOX 1288 MOBILE AL 36633
30	0904200000001	20-1N-1W	MMGOTT LLC	PO BOX 1288 MOBILE AL 36633
31	0905210000001	21-1N-1W	Tensaw Land & Timber Co. Inc.	3511 MONTLIMAR PLAZA DR MOBILE AL 36609
32	0905220000002	22-1N-1W	Bily W Robinson & Melinda Lee Edmonds	1955 STAGE COACH CHUNCHULA AL 36521
33	0905220000001	22-1N-1W	Chippewa Lakes LLC	PO BOX 2672 MOBILE AL 36652

Appendix A. Emergency Remedial and Response Risk Scenarios

Longleaf CCS Hub
Mobile County, Alabama

Table 1. Emergency Remedial and Response Risk Scenarios

	PROJECT PHASE	RISK SCENARIO	MONITORING EQUIPMENT	CONTROL IN PLACE	RESPONSE ACTION	RESPONSE PERSONNEL
1	Construction Period	***Fluid Leakage - Drilling operations:*** Hydrostatic column controlling the well decreases below the formation pressure, resulting in a sudden influx of fluid, causing a well control event with loss of containment.	* Flow sensor * Pressure sensor * Tank level indicator * Tripping displacement practices * Mud weight control	* Blowout prevention (BOP) equipment * Kill fluid * Well control training * BOP drills * BOP testing protocol * Kick drill * Lubricators for wireline operations	<u>Drilling:</u> * Stop operation * Close BOP * Clear floor and secure area * Execute well control procedure * Evaluate drilling parameters to identify root cause * Notify 24-Hour Emergency Contact and UIC Program Director and propose an action plan based on the finding * Continue operations <u>Completion:</u> * Stop operations * Close BOP * Clear floor and secure area * Execute well control procedure * Notify 24-Hour Emergency Contact and UIC Program Director and propose remediation plans. * Continue operations	* Project manager * Rig crew * Rig manager * Field superintendent
2	Construction Period	***Fluid Leakage - Drilling operations:*** Failure of surface casing completion to protect USDW while drilling resulting in cross flow of brine between formations resulting in fluid losses into the underground source of drinking water (USDW).	* Pressure sensors * Cement bond log (CBL)	* Pressure sensors * USDW will be covered with the surface casing * Casing test after cementing surface casing to check integrity * CBL to check cement bonding	* In case of influx, control the well, without compromising the shoe integrity * In the case of the shoe leaking, squeeze to regain integrity * In the case of the surface casing leaking, squeeze or install a casing patch. * Notify 24-Hour Emergency Contact and UIC Program	* Project manager * Rig crew * Rig manager * Field superintendent

	PROJECT PHASE	RISK SCENARIO	MONITORING EQUIPMENT	CONTROL IN PLACE	RESPONSE ACTION	RESPONSE PERSONNEL
					Director and propose remediation plans.	
3	Construction Period	***Fluid Leakage - Drilling through USDW:*** Improper well control during the drilling of one or more monitoring or injection wells, the drilling fluid weight exceeds the aquifer reservoir pressure, and the drilling fluid migrates into the pores and contaminates a USDW.	* Flow sensor * Pressure sensor *Mud weight control	* Well control training * Overbalance mud program	Drilling: * Stop operation * Close BOP * Clear floor and secure area * Execute well control procedure * Evaluate drilling parameters to identify root cause * Notify 24-Hour Emergency Contact and UIC Program Director and propose remediation plans. *Implement corrective actions * Continue operations	* Project manager * Rig crew * Rig manager * Field superintendent
4	Injection Period	***Fluid Leakage – UIC Wellbores*** A loss of mechanical integrity in the injection well causing a tubing/packer to leak due to corrosion damage, damage to the tubulars during installation, fatigue, higher load profiles, and other issues, that could cause communication of formation fluids with the annular casing tubing as well as sustained casing pressure. There is no loss of containment (LOC) in this scenario.	* Pressure and temperature gauges on surface and downhole real time * Pulsed-neutron logs * Annular pressure test * CO_2 leak sensors on the wellhead	* Tubing at 13CR or better * Inhibited packer fluid in annulus * Corrosion monitoring plan * Dry CO_2 injected * 13CR packers * CR tubing tailpipes below packers * New tubing or inspection of tubing before reinstalling	* Trigger Emergency Shutdown system * SCADA alarms notification to operations staff * Follow protocol to stop operation, vent, or deviate CO_2 * Notify 24-Hour Emergency Contact * Troubleshoot the well * If tubing leak is detected, notify UIC Program Director and propose an action plan based on the finding * Schedule well service to repair tubing	* Operations manager * Field superintendent * Project manager

	PROJECT PHASE	RISK SCENARIO	MONITORING EQUIPMENT	CONTROL IN PLACE	RESPONSE ACTION	RESPONSE PERSONNEL
5	Injection/ Post Injection Site Care Period	***Fluid Leakage – MW Wellbores*** A loss of mechanical integrity in the monitoring well causing a tubing/packer to leak due to corrosion damage, damage to the tubulars during installation, fatigue, higher load profiles, and others and could cause a communication of the formation fluids with the annular casing tubing as well as sustained casing pressure. There is no LOC in this scenario.	* Pressure and temperature gauges on surface and downhole real time * Pulsed-neutron logs * Annular pressure test. * CO_2 leak sensors on the wellhead	* Tubing at 13CR or better * Inhibited packer fluid in annulus * Corrosion monitoring plan * 13CR packers * CR tubing below/between packers * CR or Inconel carrier for the sensors * New tubing or inspection of tubing before reinstalling * Cased hole logging program * Monitoring wells are designed to be outside of the projected plume for most of the project which reduces the risk of contact with CO_2	* Trigger Emergency Shutdown system * SCADA alarms notification to operations staff * Notify 24-Hour Emergency Contact * Troubleshoot the well * Notify UIC Program Director and propose an action plan for well service * Schedule well service to repair tubing, isolate CO_2 zone, or abandon the well	* Operations manager * Field superintendent * Project manager * Rig crew and DH contractors
6	Injection Period	***Fluid Leakage – UIC Wellbores:*** A loss of mechanical integrity in the injection wells causing a casing leak due to corrosion, damage in the tubulars during installation, fatigue, higher load profiles, or others. This event could cause migration of CO_2 and brines through the casing, the cement sheet, and into different formations of the injection target or into USDW.	* Pressure and temperature gauges on surface and downhole real time * CO_2 leak sensors on the wellhead * DTS fiber real time alongside the casing * Flow rate monitoring * Pulsed-neutron logs * CBL/Ultra-sonic logging	* CO_2-resistant cement and metallurgic across injection zone * Injection through tubing and packer * Inhibited packer fluid in the annular * Cement to surface * Corrosion monitoring plan * Cased hole logging program * New casing and tubing installed	* Trigger Emergency Shutdown system * SCADA alarms notification to operations staff * Follow protocol to stop operation, vent, or deviate CO_2 * Notify 24-Hour Emergency Contact * Troubleshoot the well. * Evaluate if there is a movement of CO_2 or brines to USDW. In the remote event that USDW gets affected, discuss remediation options with the UIC Program Director * Notify UIC Program Director and propose an action plan based	* Operations manager * Field superintendent * Project manager * Rig crew and DH contractors * Remediation contractors

			* USDW water monitoring		on the finding and location of the leak * Schedule well service to repair the casing	
	PROJECT PHASE	**RISK SCENARIO**	**MONITORING EQUIPMENT**	**CONTROL IN PLACE**	**RESPONSE ACTION**	**RESPONSE PERSONNEL**
7	Injection Period/ Post Injection Site Care Period	***Fluid Leakage – MW Wellbores:*** A loss of mechanical integrity in the monitoring well causing a casing leak due to corrosion, damage in the tubulars during installation, fatigue, higher load profiles, and others. This event could cause a migration of CO_2 and brines through the casing, the cement sheet, and into different formations of the injection target or into USDW.	* Pressure and temperature gauges on surface and downhole real time * CO_2 leak sensors on the wellhead * Pulsed-neutron logs * CBL/Ultra-sonic logging * USDW water monitoring	* CO_2-resistant cement across injection zone * 13CR packers * Inhibited packer fluid in the annular * Cement to surface * Corrosion monitoring plan * Cased hole logging program * New casing * New or inspected tubing before reinstallation * Monitoring wells are designed to be outside of the projected plume for most of the project's life cycle which minimizes the risk of contact with CO_2	* Trigger Emergency Shutdown system * SCADA alarms notification to operations staff * Notify 24-Hour Emergency Contact * Troubleshoot the well * Evaluate if there is a movement of CO_2 or brines to USDW. In the remote event that USDW gets affected, discuss remediation options with the UIC Program Director * Notify UIC Program Director and propose an action plan based on the findings and the location of the leak. * Schedule well service to repair the casing	* Operations manager * Field superintendent * Project manager * Rig crew and DH contractors * Remediation contractors
8	Injection Period / Post Injection Site Care Period	***Fluid Leakage – Legacy Wellbores:*** Brines and CO_2 could migrate through poor cement bonding, cement degradation, or cracking in the cement of plugged and abandoned (P&A) wells.	* Time-lapse vertical seismic profile survey * USDW water sampling	* Legacy wells are properly abandoned for brine movement because of pressurization of injection zone * Injectors will be abandoned as soon as CO_2 injection ends, except if they are left as monitoring wells	* Notify 24-Hour Emergency Contact * Evaluate if it's a positive CO_2 release because of a leak in the legacy/P&A well * Notify regulator and propose plan to repair the well, delineate the area, and identify potential resources affected * Discuss specific remediation actions and monitoring plans	* Operations manager * Field superintendent * Project manager * Rig crew and DH contractors * Remediation contractors

	PROJECT PHASE	RISK SCENARIO	MONITORING EQUIPMENT	CONTROL IN PLACE	RESPONSE ACTION	RESPONSE PERSONNEL
					* Execute program, monitor, and evaluate efficacy	
9	Injection	***Fluid Leakage – Faults and Fractures:*** During injection, the pressurization of the injection zone exceeds the sealing capacity of the confining zone above or if there are features such as fault or fractures that are reactivated. Creating a leakage pathway for CO_2 and brine to migrate to a shallower formation, including a USDW.	* USDW water sampling * Time-lapse vertical seismic profile survey * Pulsed-neutron log in injector and monitoring wells	* Injection is limited to 90% of frac gradient * Extensive characterization of the rocks shows good sealing capacity * If the confining zone above the Paluxy fails, the Selma Group will act as a buffer formation before CO_2 or brines are able to reach the USDW	* Notify 24-Hour Emergency Contact * Assess root cause by reviewing monitoring data * Notify UIC Program Director * If necessary, follow protocol to stop injection. * If necessary, conduct geophysical survey to delineate potential leak path * Evaluate if there is a movement of CO_2 or brines to USDW. If USDW gets affected, discuss with UIC Program Director remediation options, action plan, and monitoring program. * Actions to restore injection will depend on the nature of the leak path and the extent. Operator needs to reevaluate model and discuss action plan with UIC Program Director	* Operations manager * Field superintendent * Geologist * Reservoir engineer * Project manager * Remediation contractors
10	Injection Period	***Fluid Leakage - Geomechanical Seal Failure*** Elevated well bottomhole pressure (BHP) either exceeds the permitted maximum injection pressure or the estimated maximum injection pressure is inaccurate (i.e., the true fracture pressure is lower than the estimated maximum pressure) in the injection zone, resulting in the failure of the confining system and leading	* Pressure gauges on surface and downhole real time * USDW water sampling * Time-lapse seismic profile survey	* Injection is limited to less than 90% of the fracture gradient * Core and geomechanical testing and geochemical modeling of the upper confining zone show good sealing capacity and fluid compatibility, respectively * If the confining zone above the Paluxy fails, the Selma	* Trigger Emergency Shutdown system * SCADA alarms notification to operations staff * Follow protocol to stop injection * Designate an exclusion zone, and provide appropriate PPE for protection of onsite personnel * Notify 24-Hour Emergency Contact	* Operations manager * Field superintendent * Monitoring staff * Geologist * Reservoir engineer * Project manager * Remediation contractors

	PROJECT PHASE	RISK SCENARIO	MONITORING EQUIPMENT	CONTROL IN PLACE	RESPONSE ACTION	RESPONSE PERSONNEL
		to vertical migration of CO_2 or brine to a USDW, the surface or atmosphere (CO_2 only).	* Pulsed-neutron log in injector and monitoring wells	Group will act as a buffer formation before CO_2 or brines are able to reach the USDW * Microfracture test prior to receiving authorization to operate, confirm formation breakdown pressure.	* Assess root cause by reviewing monitoring data * If required, conduct geophysical survey to delineate potential leakage pathway * Evaluate if there is a movement of CO_2 or brines to USDW. * Notify UIC Program Director and propose remediation options, action plan, and monitoring program * Actions to restore injection will depend on the nature of the leak path and the extent. Operator needs to reevaluate model and discuss action plan with UIC Program Director	
11	Injection Period	***Fluid Leakage - Surface Infrastructure:*** Vehicle strikes other surface equipment (e.g., tank battery pumps/compressors, etc.), causing the release of CO_2 at the surface.	* Use of protective equipment, such as bollards, fences, locking gates * Use of appropriate fencing and signage	* Temperature-controlled building and/or containment, as required by regulation or law, will be proposed to protect the surface equipment and other instrumentation (i.e., interrogator, gauges, meters, etc.).	* Trigger Emergency Shutdown system * SCADA alarms notification to operations staff * Designate an exclusion zone, and provide appropriate PPE for protection of onsite personnel * Follow protocol to shut down CO_2 delivery * If there is injured personnel, call emergency team, and execute evacuation protocol * Notify 24-Hour Emergency Contact * Clear location and secure the perimeter. If possible, install containment devices around the location.	* Operations manager *Field superintendent *Project manager *Plant manager *Remediation contractors

	PROJECT PHASE	RISK SCENARIO	MONITORING EQUIPMENT	CONTROL IN PLACE	RESPONSE ACTION	RESPONSE PERSONNEL
					* Evaluate environmental impact (soil, water, fauna, vegetation), * Assess mechanical integrity of the system * Notify UIC Program Director and propose repair actions * Repair or replace equipment	
12	Injection Period	***Fluid Leakage - Surface Infrastructure:*** Failure of a valve results in leakage of CO_2 with potential impacts to health, safety, and the environment, particularly if the leak is not detected and corrected.	* Routine field inspections * Routine inspection of emergency alert systems, monitoring systems and controls.	* Equipment upstream or downstream of the failed valve can be used to isolate the problem as necessary * Preventative maintenance * Periodic inspections	* Trigger Emergency Shutdown system * SCADA alarms notification to operations staff * If there is injured personnel, call emergency team, and execute evacuation protocol * Notify 24-Hour Emergency Contact * Clear location and secure the perimeter. I * Evaluate environmental impact * Assess mechanical integrity of the system * Notify UIC Program Director and propose repair actions * Repair or replace equipment	* Operations manager *Field superintendent *Plant manager *Remediation contractors *Emergency teams
13	Injection Period	***Fluid Leakage – Surface Infrastructure:*** The CO_2 stream is blocked between valves on the surface, heated (e.g., by the sun), and expands to rupture the line or flowline on the site is plugged and the pressure sensor fails to detect the change, resulting in a CO_2 leak.	* Pressure, temperature, and flowmeter sensors in real time * Field inspections	* Relief valves (e.g., Pressure Safety Valves) in areas where this is a risk as part of the design process * Equipment upstream or downstream of the failed valve can be used to isolate the problem as necessary * Cleaning protocols: - Wiping the lines - Testing with water	* Trigger Emergency isolation valves * SCADA alarms notification to operations staff * Follow protocol to shut down CO_2 delivery * If there is injured personnel, call emergency team, and execute evacuation protocol * Notify 24-Hour Emergency Contact to activate emergency	* Operations manager *Field superintendent *Plant manager *Remediation contractors

				- Performing cleaning runs to remove any debris. * Witches hat (cone strainer) filters can be used to filter out large pieces of debris on startup	plan, reverse 9-1-1 protocol for residents or occupants in proximity to occurrence. * Clear location and secure the perimeter. If possible, install containment devices around the location * Evaluate environmental impact (soil, water, fauna, vegetation), * Assess mechanical integrity of the system * Notify UIC Program Director and propose repair actions * Repair or replace equipment	
	PROJECT PHASE	**RISK SCENARIO**	**MONITORING EQUIPMENT**	**CONTROL IN PLACE**	**RESPONSE ACTION**	**RESPONSE PERSONNEL**
14	Injection Period	***Fluid Leakage – Natural Disaster:*** A natural disaster event - e.g., hurricane, lightning, tornadoes, floods, landslides – impacts the pipelines or flowlines at the storage location, forcing the release of CO_2 at the surface.	* Pressure and flowmeter sensors in real time * Field inspections	* HAZOP review * ESD valve installed near the wellhead so it will cease injection whenever any leak occurs downstream or upstream of the ESD * Weather monitoring	* Trigger Emergency isolation valves * SCADA alarms notification to operations staff * Follow protocol to shut down CO_2 delivery if the automatic shutoff device is not functional * If there is injured personnel, call emergency team, and execute evacuation protocol * Notify 24-Hour Emergency Contact * Clear the location and secure the perimeter. If possible, install containment devices around the location. *Assess mechanical integrity of the pipelines or flowlines * Notify UIC Program Director and propose action plan	* Operations manager * Field superintendent * Project manager *Remediation contractors *Emergency teams

	PROJECT PHASE	RISK SCENARIO	MONITORING EQUIPMENT	CONTROL IN PLACE	RESPONSE ACTION	RESPONSE PERSONNEL
					* Evaluate environmental impact (soil, water, fauna, vegetation), and present remediation plan to the UIC Program Director for approval * Execute remediation, and install additional monitoring system as needed	
15	Injection Period	***Fluid Leakage – Surface Infrastructure:*** Failure of CO_2 transport flowlines from the CO_2 capture system to Longleaf CCS Hub CO_2 Injection wellhead.	* Surface P/T gauges and flowmeters at inlet and delivery point.	* Preventive maintenance * Periodic inspections * Monitoring devices at both ends of the transmission pipeline and flowline	* Trigger emergency isolation valves * SCADA alarms notification to operations staff * Follow protocol to shut down CO_2 delivery * Detect CO_2 stream release and its location * Initiate evacuation plan * Notify 24-Hour Emergency Contact * Transmission line and/or flowline failure will be inspected to determine the root cause of the failure * Notify UIC Program Director and propose action plan * Repair/replace the damaged transmission line or flowline, and if warranted, put in place the measures necessary to eliminate such events in the future	* Operations manager * Field superintendent * Remediation contractors * Emergency teams * Plant manager/ contact
16	Injection Period	***Loss of Containment - Vertical Migration via injection well:***	* CO_2 leak sensors on the wellhead	* CO_2-resistant cement and metallurgic across injection zone	* Trigger Emergency Shutdown system * SCADA alarms notification to operations staff	* Operations manager * Field superintendent * Project manager

		During the life of the injector wells, there are induced stresses and chemical reactions on the tubulars and cement exposed to the CO_2 pressure and plume. Changes in temperature and injection pressure create stresses in the tubulars trying to expand or contract, and it can lead to microannulus effects, resulting in fugitive movement of brines/CO_2.	* DTS fiber real time alongside the casing * USDW water monitoring * Pulsed-neutron logs (PNL) to be run for external integrity * CBL/Ultra-sonic logging * Pressure gauges at surface * Flow rate monitoring	* Injection through tubing and packer, 13CR or better tubing and 13CR packers. * Cement to surface * Cased hole logging program * USDW covered as second barrier with surface casing and surface cement sheet * New casing installed, 13CR or better.	* Follow protocol to stop operation, vent, or deviate CO_2 * Notify 24-Hour Emergency Contact * Troubleshoot the well * Evaluate if there is a movement of CO_2 or brines to USDW. * Notify UIC Program Director and discuss action plan to repair the well or P&A based on the findings of the assessment	* Rig crew and DH contractors * Remediation contractors
	PROJECT PHASE	**RISK SCENARIO**	**MONITORING EQUIPMENT**	**CONTROL IN PLACE**	**RESPONSE ACTION**	**RESPONSE PERSONNEL**
17	Injection Period/ Post Injection Site Care Period	***Loss of Containment - Vertical Migration via monitoring well:*** During the life of the injector wells, there are induced stresses and chemical reactions on the tubulars and cement exposed to the CO_2 pressure and plume. Changes in temperature and injection pressure create stresses in the tubulars trying to expand or contract, and it can lead to microannulus effects, resulting in fugitive movement of brines/CO_2.	* CO_2 leak sensors on the wellhead * USDW water monitoring * Pulsed-neutron logs to be run for external integrity * CBL/Ultra-sonic logging * Pressure gauges at surface	* CO_2-resistant cement across injection zone * Cement to surface * Case hole logging program * USDW covered as second barrier with surface casing and surface cement sheet * New casing installed, 13CR or better. * Monitoring wells are designed to be outside of the plume for most of the injection period	* Trigger Emergency Shutdown system * SCADA alarms notification to operations staff * Notify 24-Hour Emergency Contact * Troubleshoot the well. * Evaluate if there is a movement of CO_2 or brines to USDW. * Notify UIC Program Director and discuss action plan to repair the well or P&A based on the findings of the assessment	* Operations manager * Field superintendent * Project manager * Rig crew and DH contractors * Remediation contractors
18	Injection Period/ Post Injection Site Care Period	***Loss of Containment-Lateral Migration of CO_2 Outside Defined AOR:*** The CO_2 plume moves faster or in an unexpected pattern and expands	* Time-lapse vertical seismic profile surveys * Pulsed-neutron logs in monitoring wells	* Detailed geologic model with stratigraphic wells as calibration * Seismic survey integrated in the model	Injection period: * Trigger Emergency Shutdown system * SCADA alarms notification to operations staff	* Operations manager * Field superintendent * Geologist * Reservoir engineers * Project manager

		beyond the secured pore space for the project and the AoR.	* Pressure and temperature gauges real time in monitoring wells	* Extensive characterization of the rocks and formation * Periodic review of CO_2 and pressure plume within AoR every 5 years * Monitor the plume over PISC	* Notify 24-Hour Emergency Contact * Review monitoring data and trends and compare with the simulation. * Notify UIC Program Director, propose action plan and request to keep injection process while AoR is reviewed, if the data show that CO_2 will stay in the secured pore space. * Perform logging in monitoring wells. * Conduct geophysical survey as required to evaluate AoR. * Recalibrate model and simulate new AoR * Assess if additional corrective actions are needed and if it's required to secure additional pore space * Assess if any remediation is needed, and discuss action plan with UIC Program Director * Present AoR review to UIC Program Director for approval and adjust monitoring plan <u>Post Injection Site Care Period:</u> * SCADA alarms notification to monitoring personnel * Notify 24-Hour Emergency Contact * Review monitoring data and trends, compare with the simulation * Notify UIC Program Director and propose action plan	

	PROJECT PHASE	RISK SCENARIO	MONITORING EQUIPMENT	CONTROL IN PLACE	RESPONSE ACTION	RESPONSE PERSONNEL
					* Conduct geophysical survey as required to evaluate AoR * Recalibrate model, and simulate new AoR * Assess if additional corrective actions are needed and if it's required to secure additional pore space * Assess if any remediation is needed, and discuss action plan with UIC Program Director	
19	Injection Period/ Post Injection Site Care Period	***Containment - Pressure Propagation:*** A "pressure front" that exceeds the minimum pressure necessary to cause fluid flow from the injection zone into a USDW through a hypothetical conduit (i.e., an artificial penetration that is perforated in both intervals).	* Pulsed-neutron logs *Pressure gauges on surface and downhole real time * USDW water monitoring * Flow rate monitoring * Time-lapse vertical seismic profile survey (AoR review periods) * Incremental leakage modeling to validate a lack of potential for fluid movement into the USDW.	* Detailed geologic model with stratigraphic wells as calibration * Seismic survey integrated in the model * Extensive characterization of the rocks and formation * Periodic review of CO_2 and pressure plume within AoR every 5 years * Monitor the plume until stabilization (min 10 years) * USDW covered as second barrier with surface casing and surface cement sheet * Cased hole logging program	<u>Injection period:</u> * Identification by monitoring staff * Notify 24-Hour Emergency Contact * Review monitoring data and trends and compare with the simulation * If endangerment to USDW is suspected follow shut down procedure. * Notify UIC Program Director and propose action plan and request to keep injection process while AoR is reviewed, if the data shows that the CO_2 will stay in the secured pore space * Perform logging in monitoring wells * Conduct geophysical survey as required to evaluate AoR * Recalibrate model and simulate new AoR * Assess if additional corrective actions are needed and if it's	* Operations manager * Field superintendent * Monitoring staff * Geologist * Reservoir engineers * Project manager * Remediation contractors

					required to secure additional pore space * Assess if any remediation is needed, and discuss action plan with UIC Program Director * Present AoR review to UIC Program Director for approval and adjust monitoring plan <u>Post Injection Site Care Period:</u> * Identification by monitoring staff * Notify 24-Hour Emergency Contact * Review monitoring data and trends and compare with simulations * Notify UIC Program Director and propose action plan * Conduct geophysical survey as required to evaluate AoR * Recalibrate model, and simulate new AoR * Assess if additional corrective actions are needed and if it's required to secure additional pore space * Evaluate if there is a movement of CO_2 or brines to USDW. In the remote event that USDW gets affected, discuss remediation options with the UIC Program Director	

	PROJECT PHASE	RISK SCENARIO	MONITORING EQUIPMENT	CONTROL IN PLACE	RESPONSE ACTION	RESPONSE PERSONNEL
20	Injection Period	***External impact – UIC Well:*** During injection, the wellhead is hit by a massive object that causes major damages to the equipment. The well gets disconnected from the pipeline and from the shutoff system and leads to a loss of containment of CO_2 and brine.	* Pressure, temperature, and flow sensors in real time * Field inspections	* Fence location and block direct access to the wellhead * Bollards and/or concrete barriers installed to protect installation * No populated area	* Trigger emergency isolation valves * SCADA notification to monitoring or operations staff * Follow protocol to shut down CO_2 delivery if the automatic shutoff device is not functional * Designate an exclusion zone, and provide appropriate PPE for protection of onsite personnel * If there is injured personnel, call emergency team, and execute evacuation protocol * Notify 24-Hour Emergency Contact * Clear the location and secure the perimeter. If possible, install containment devices around the location. * Contact well control special team to execute blowout emergency plan that may include but is not limited to capping the well, secure location, drill relief well to kill injector, properly repair or abandon injection well. This plan would be discussed with UIC Program Director * Evaluate environmental impact (soil, water, fauna, vegetation) * Notify UIC Program Director and propose action plan * Execute remediation, and install monitoring system as needed	* Operations manager * Field superintendent * Project manager * Rig crew and DH contractors * Remediation contractors * Well control specialist

	PROJECT PHASE	RISK SCENARIO	MONITORING EQUIPMENT	CONTROL IN PLACE	RESPONSE ACTION	RESPONSE PERSONNEL
21	Injection Period/ Post Injection Site Care Period	***External impact – MW:*** The wellhead of the deep monitoring well is hit by a massive object that causes major damages leading to a LOC. Since the well is open to the formation pressure at the injection zone, formation fluids have the potential to flow and spill on the location.	* Pressure, temperature, and flow sensors in real time * Field inspections * Incremental leakage modeling to validate a lack of potential for fluid movement into the USDW.	* Fence location and block direct access to the wellhead * Bollards and/or concrete barriers installed to protect installation * No populated area * Lined pads * Reduced pressure in the monitoring well compared with the injector well on bottom	* SCADA alarms notification to operations staff * Designate an exclusion zone, and provide appropriate PPE for protection of onsite personnel * If there is injured personnel, call emergency team, and execute evacuation protocol * Notify 24-Hour Emergency Contact * Clear the location and secure the perimeter. If possible, install containment devices around the location. * Contact well control special team to execute blowout emergency plan that may include, but is not limited to, capping the well, securing the location, drilling relief well to kill the injector, properly repairing, or abandoning the injection well. * Evaluate environmental impact (soil, water, fauna, vegetation) * Notify UIC Program Director and propose action plan * Execute remediation, and install monitoring system as needed	* Operations manager * Field superintendent * Project manager * Rig crew and DH contractors * Remediation contractors * Well control specialist
22	Injection Period	***External impact – Pipeline:*** During injection, the CO_2 pipeline is hit causing major damages and LOC of the CO_2.	* Pressure, temperature, and flowmeter sensors in real time * Field inspections	* Buried pipe * Bollards and/or concrete barriers installed to protect aboveground piping at valve stations * Painting for visibility in varied weather conditions	* Trigger emergency isolation valves * SCADA alarms notification to operations staff * If there is injured personnel, call emergency team, and execute evacuation protocol	* Operations manager * Field superintendent * Remediation contractors * Emergency teams * Plant manager/ contact

			* Bollards and/or concrete barriers installed to protect aboveground piping at valve stations * Appropriate warning signage/painting * Appropriate fencing	* Signage along right of way as needed * Pipeline is part of One Call system	* Designate an exclusion zone, and provide appropriate PPE for protection of onsite personnel * Verify CO_2 flow was shut off by the system or start protocol to stop flow * Notify 24-Hour Emergency Contact * Clear the location and secure the perimeter. If possible, install containment devices around the location. * Evaluate environmental impact (soil, water, fauna, vegetation) * Notify UIC Program Director and propose action plan * Execute remediation, and install monitoring system as needed	
	PROJECT PHASE	**RISK SCENARIO**	**MONITORING EQUIPMENT**	**CONTROL IN PLACE**	**RESPONSE ACTION**	**RESPONSE PERSONNEL**
23	Injection Period	***Monitoring Equipment Failure or Malfunction:*** Failure on the monitoring system/ alarm devices that lead to over pressurization of the system or reservoir beyond the design limits, causing fracturing of the reservoir, leaks or failure on equipment and tubulars, and damage of the facilities.	* Real-time pressure monitoring system and redundancy * Field inspections	* Preventive maintenance * Periodic inspections	* SCADA alarms notification to operations staff * If there are injured personnel, call emergency team, and execute evacuation protocol * Designate an exclusion zone, and provide appropriate PPE for protection of onsite personnel * Notify 24-Hour Emergency Contact * Assess mechanical integrity of the system, and propose repair actions if needed * Assess any potential environmental impact * Notify UIC Program Director and propose action plan	* Operations manager * Field superintendent * Project manager * Remediation contractors * Emergency teams * Geologist * Reservoir engineers * Monitoring staff

	PROJECT PHASE	RISK SCENARIO	MONITORING EQUIPMENT	CONTROL IN PLACE	RESPONSE ACTION	RESPONSE PERSONNEL
					* Repair or replace instrumentation. Calibrate equipment. * Review monitoring records, and if needed, perform an injectivity test or falloff test to evaluate reservoir	
24	Injection Period/ Post Injection Site Care Period	***Injection or Monitoring Equipment Failure:*** Failure of surface injection or monitoring equipment including injection pumps, valves, gauges, meters, sensors, electrical, or other equipment results in potentially unsafe operating conditions and requires an emergency response at the site.	* Real-time monitoring system and redundancy * Field inspections * Routine inspection/testing of emergency alert systems, monitoring systems and controls systems.	* Preventive maintenance * Periodic inspections	* SCADA alarms notification to operations staff * If there are injured personnel, call emergency team, and execute evacuation protocol * Designate an exclusion zone, and provide appropriate PPE for protection of onsite personnel * Notify 24-Hour Emergency Contact * Assess mechanical integrity of the system, and propose repair actions if needed * Assess any potential environmental impact * Notify UIC Program Director and propose action plan * Perform Lockout/Tagout (LOTO) for defective equipment until it is properly replaced * Repair or replace instrumentation. Calibrate equipment. * If the assessment allows resuming injection safely, discuss plan with the UIC Program Director and get approval	* Operations manager * Field superintendent * Project manager * Remediation contractors * Emergency teams * Geologist * Reservoir engineers * Monitoring staff

	PROJECT PHASE	RISK SCENARIO	MONITORING EQUIPMENT	CONTROL IN PLACE	RESPONSE ACTION	RESPONSE PERSONNEL
25	Injection Period/ Post Injection Site Care Period	***Injection or Monitoring Equipment Failure:*** Malfunction of subsurface injection/monitoring well subsurface equipment including gauges, fiber, cables, or capillary string, requiring an emergency response at the site.	* Real-time monitoring system and redundancy * Field inspections * Routine inspection/testing of emergency alert systems, monitoring systems and controls systems.	* Preventive maintenance * Periodic inspections	* SCADA alarms notification to operations staff * If there are injured personnel, call emergency team, and execute evacuation protocol * Notify 24-Hour Emergency Contact * Assess mechanical integrity of the system, and propose repair actions if needed * Assess any potential environmental impact * Notify UIC Program Director and propose action plan * If the assessment allows resuming injection safely, discuss plan with the UIC Program Director and get approval * Repair or replace instrumentation. Calibrate equipment. * Review monitoring records, and if needed, perform an injectivity test or falloff test to evaluate reservoir	* Operations manager * Field superintendent * Project manager * Remediation contractors * Emergency teams * Geologist * Reservoir engineers * Monitoring staff
26	Injection Period	***Injection or Monitoring Equipment Failure:*** A large pressure drop in the CO_2 stream results in low temperatures that could cause harm to personnel or damage/brittleness in materials (e.g., carbon steel and elastomers).	* Real time monitoring system of the CO_2 injection stream	* Use of materials that are rated for low temperatures * Controlled CO_2 stream composition	* SCADA alarms notification to operations staff * If there are injured personnel, call emergency team, and execute evacuation protocol * Designate an exclusion zone, and provide appropriate PPE for protection of onsite personnel	* Operations manager *Field superintendent *Plant manager *Emergency teams

	PROJECT PHASE	RISK SCENARIO	MONITORING EQUIPMENT	CONTROL IN PLACE	RESPONSE ACTION	RESPONSE PERSONNEL
					* Notify 24-Hour Emergency Contact * Assess mechanical integrity of the system, and propose repair actions if needed * Assess any potential environmental impact, and propose remedial action with the UIC Program Director, if needed * If the assessment allows resuming injection safely, discuss plan with the UIC Program Director and obtain approval * Repair or replace any damaged equipment and recalibrate * Review monitoring records and, if needed, adjust CO_2 accordingly	
27	Injection Period	***Induced Seismicity:*** Pressurization of the reservoir, during injection of CO_2, activates preexisting fault planes and creates a displacement that causes a seismic event. If it's a major event (>2.7 Richter), it could compromise the integrity of the wells, facilities, or pipeline.	* Geophones array to monitor induced seismicity * DAS fiber * Pulsed-neutron logs * CBL/Ultra-sonic logging	* A detailed geomechanical model was created to evaluate the storage complex * The region is seismically stable * Cased hole logging program	* SCADA alarms notification to operations staff * If there is injured personnel or property damages, call emergency team, and execute evacuation protocol and secure location * Notify 24-Hour Emergency Contact * Assess any potential environmental impact * Notify UIC Program Director and propose action plan, if needed * Define new injection parameters and get approval from the UIC Program Director	* Operations manager * Field superintendent * Project manager * Remediation contractors * Emergency teams * Geologist * Reservoir engineers * Monitoring staff

	PROJECT PHASE	RISK SCENARIO	MONITORING EQUIPMENT	CONTROL IN PLACE	RESPONSE ACTION	RESPONSE PERSONNEL
					* If the assessment allows resuming injection safely, increase surveillance to validate effectiveness of the actions	
28	Injection Period/ Post Injection Site Care Period	***Induced Seismicity:*** Other subsurface injection (e.g., saltwater disposal) causes pressure changes and induced seismicity at the Project Site or induced seismicity occurs at a nearby site that impacts the Project site.	* Geophones array to monitor induced seismicity * DAS fiber * Pressure gauges at surface * Pulsed-neutron logs * CBL/Ultra-sonic logging	* Detailed geomechanical model was created to evaluate the storage complex * Cased hole logging program	* SCADA alarms notification to operations staff * If there is injured personnel or property damage, call emergency team, and execute evacuation protocol and secure location * Follow protocol to stop injection (injection period) * Notify 24-Hour Emergency Contact * Assess any potential environmental impact * Notify UIC Program Director and propose action plan, if needed * Review regional information as well as monitoring records to determine the origin of the event (natural or induced) * If the assessment allows resuming injection safely, increase surveillance to validate effectiveness of the actions (injection period)	* Operations manager * Field superintendent * Project manager * Geologist * Monitoring staff * Remediation contractors
29	Injection Period/ Post Injection Site Care Period	***Major seismic event*** Natural seismicity causes LOC by opening transmissive features in the confining zone, resulting in release of CO_2 to a USDW, surface, or atmosphere.	* Geophones array to monitor induced seismicity * DAS fiber * Pulsed-neutron logs	* The region is seismically stable * Cased hole logging program	* SCADA alarms notification to operations staff * If there is injured personnel or property damage, call emergency team, and execute evacuation protocol and secure location	* Operations manager * Field superintendent * Project manager * Remediation contractors * Emergency teams * Geologist

	PROJECT PHASE	RISK SCENARIO	MONITORING EQUIPMENT	CONTROL IN PLACE	RESPONSE ACTION	RESPONSE PERSONNEL
			* CBL/Ultra-sonic logging		* Designate an exclusion zone, and provide appropriate PPE for protection of onsite personnel * Notify 24-Hour Emergency Contact * Assess any potential environmental impact * Notify UIC Program Director and propose action plan, if needed * If the assessment allows resuming injection safely, increase surveillance to validate effectiveness of the actions (injection period)	* Reservoir engineers * Monitoring staff
30	Injection Period/ Post Injection Site Care Period	***Other Major Natural Disaster*** Natural disaster that limits or endangers the normal operation of the Hub.	* Weather monitoring	* Project safety program * Condition/atmospheric monitoring. * Emergency shutdown valves	* SCADA alarms notification to operations staff * If there is injured personnel or property damage, call emergency team, and execute evacuation protocol and secure location * Follow protocol to stop injection * Notify 24-Hour Emergency Contact * Assess mechanical integrity of the system * Assess any potential environmental impact * Notify UIC Program Director and propose repair actions based on findings * If the assessment allows resuming injection safely, increase surveillance to validate effectiveness of the actions	* Operations manager * Field superintendent * Project manager * Remediation contractors * Emergency teams * Geologist * Reservoir engineers * Monitoring staff

31	Injection Period	***Accidents or Unplanned Event:*** Loss of electricity causing injection to cease.	*Field inspections	* PLC with Uninterrupted Power Supply (UPS) * "Fail-Closed" shutdown valves *Consider backfeed to redundant generation sources or generation sources *Install industry standard weather mitigation on distribution lines *Solar Back-up if required	* SCADA alarms notification to operations staff * PLC/UPS programmed to initiate a closure of shutdown valves in fail safe position (Fail-Closed) * PLC/UPS will continue to monitor the shutdown and report back to the SCADA system for personnel * Designate an exclusion zone, and provide appropriate PPE for protection of onsite personnel * Verify CO_2 flow was shut off by the system or start manual protocol to stop flow, visual inspection, and manually close valves. * Notify 24-Hour Emergency Contact * Notify UIC Program Director within 24-hours of shut-in * Notify UIC Program Director of start-up procedure.	* Operations manager * Field superintendent * Project manager

Appendix B. Emergency Contact List
Longleaf CCS Hub, Mobile County, Alabama
Updated 3/23/2023

Facility Contacts	Phone Number
24-Hour Emergency Contact During Construction: Project Manager – Ryan Choquette	402-547-1132
24-Hour Emergency Contact During Operation and Post-Injection: Operations Manager – TBD	TBD
Local Agencies	
Mt. Vernon Fire Department	251-829-6040
Mt. Vernon Police Department	251-829-6631 or 251-829-9966
Citronelle Fire & Rescue	251-866-9780 or 251-899-7973
Citronelle Police Department	251-866-2823 or 251-866-5527
Satsume Fire Department	251-675-1440
Saraland Fire Rescue Department	251-679-5506
Turnerville Volunteer Fire Department	251-866-9911
Mobile Fire-Rescue Department	251-208-7351
Mobile County Emergency Management	251-460-8000
Washington County Emergency Management Agency	251-847-2668
State Agencies	
Alabama Emergency Management Agency – 24-Hour State Warning Point	800-843-0699
Alabama Department of Environmental Management – Montgomery Field Office	334-260-2700
Geological Survey of Alabama	205-349-2852
Alabama Public Service Commission – Gas Pipeline Safety	334-242-5778
Federal Agencies	
U.S. EPA Region 4 UIC Program Director	404-562-9474
National Response Center (NRC)	800-424-8802

Longleaf CCS Hub

Longleaf CCS, LLC

Injection Well Plugging Plan

40 CFR 146.92

Facility Information

Facility Name: Longleaf CCS Hub

Facility Contact: Longleaf CCS, LLC
14302 FNB Parkway
Omaha, NE 68154

Well Locations: Mobile County, Alabama
LL#1: Latitude: 31.071303° N
Longitude: -88.094703° W
LL#2: Latitude: 31.070774° N
Longitude: -88.074523° W
LL#3: Latitude: 31.0447129° N
Longitude: -88.0736318° W
LL#4: Latitude: 31.0569516° N
Longitude: -88.1047433° W

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List of Acronyms/Abbreviations

AoR	Area of Review
CCS	Carbon capture and storage
CO_2	Carbon dioxide
CMG	Computer Modelling Group
DOE	Department of Energy
DAS	Distributed Acoustic Sensing
DTS	Distributed Temperature Sensing
EPA	Environmental Protection Agency
ERRP	Emergency and Remedial Response
ft	Feet
LL	Longleaf
MIT	Mechanical Integrity Test
MMcf/d	Million cubic feet/day
mg/l	Milligrams per liter
mt	Metric tons
Mt	Millions of metric tons
mt/d	Metric tons per day
mt/y	Metric tons per day
MT/y	Millions of metric tons per year
PISC	Post-Injection Site Care
PNC	Pulsed Neutron Capture Log
psi	Pounds per square inch
psi/ft	Pounds per square inch per foot
SS	Sub-Sea
TVD	True Vertical Depth
UIC	Underground Injection Control
USDW	Underground Source of Drinking Water

A. Introduction

Outlined in the following document is the description of the process that the Longleaf CCS Hub will follow to plug proposed CO_2 injection wells LL#1, LL#2, LL#3, and LL#4 in accordance with the EPA's requirements under 40 CFR 146.92 and 40 CFR 146.93(e) and the State of Alabama's requirements under ASR 400-1-4-.15-.16 to ensure that the abandoned wells maintain integrity and will not pose a threat to USDWs. Plugging activities at an injection well will begin following the cessation of CO_2 injection in that well. However, in certain situations, Longleaf CCS, LLC may choose to delay plugging selected injection wells and to use them, for some period of time, to monitor in-zone reservoir conditions post-injection. If delaying plugging of an injection well, per ASR 400-1-4-.17, Longleaf CCS, LLC will submit a request to the Alabama Oil and Gas Board for the well to be placed into a temporarily abandoned injection well status for a period of not more than a year, with a subsequent request submitted for a 1-year extension.

Following are notifications and reporting required with plugging an injection well, which shall be submitted separately for each well:

- **60-Day Notification**: The Longleaf CCS Hub will notify the UIC Program Director in writing at least 60 days prior to the plugging of an injection well. Any changes to this plan shall be submitted no later than with the notification (40 CFR 146.92(c)).
- **Well Plugging Report**: Within 30 days of plugging an injection well, Longleaf CCS Hub will submit a well plugging report using OGB AL Form OGB-11 to the UIC Program Director and Alabama Oil and Gas Board (40 CFR 146.92(d); ASR 400-1-4-.15).

A.1 Injection Well Configuration

Prior to plugging, the injection well configuration will include conductor casing, surface casing, and long string casing, all cemented to surface. The wells will also have an injection tubing string. Injection wells without sliding sleeves in the tubing string will have a configuration as shown in **Figure 1**. Injection wells that utilize sliding sleeves in the tubing string will have a configuration as shown in **Figure 2**.

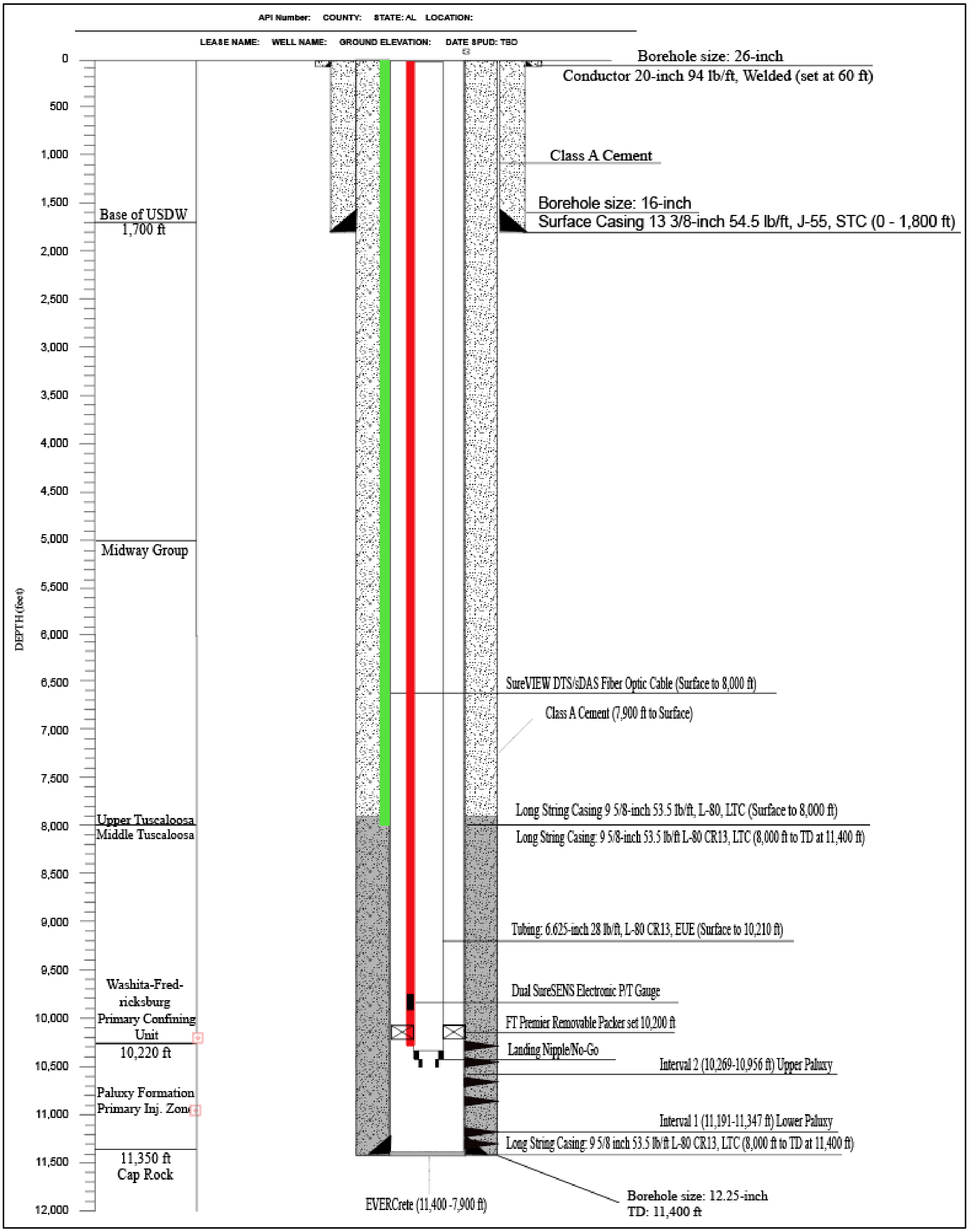

Figure 1. Injection Well Configuration, without Sliding Sleeves

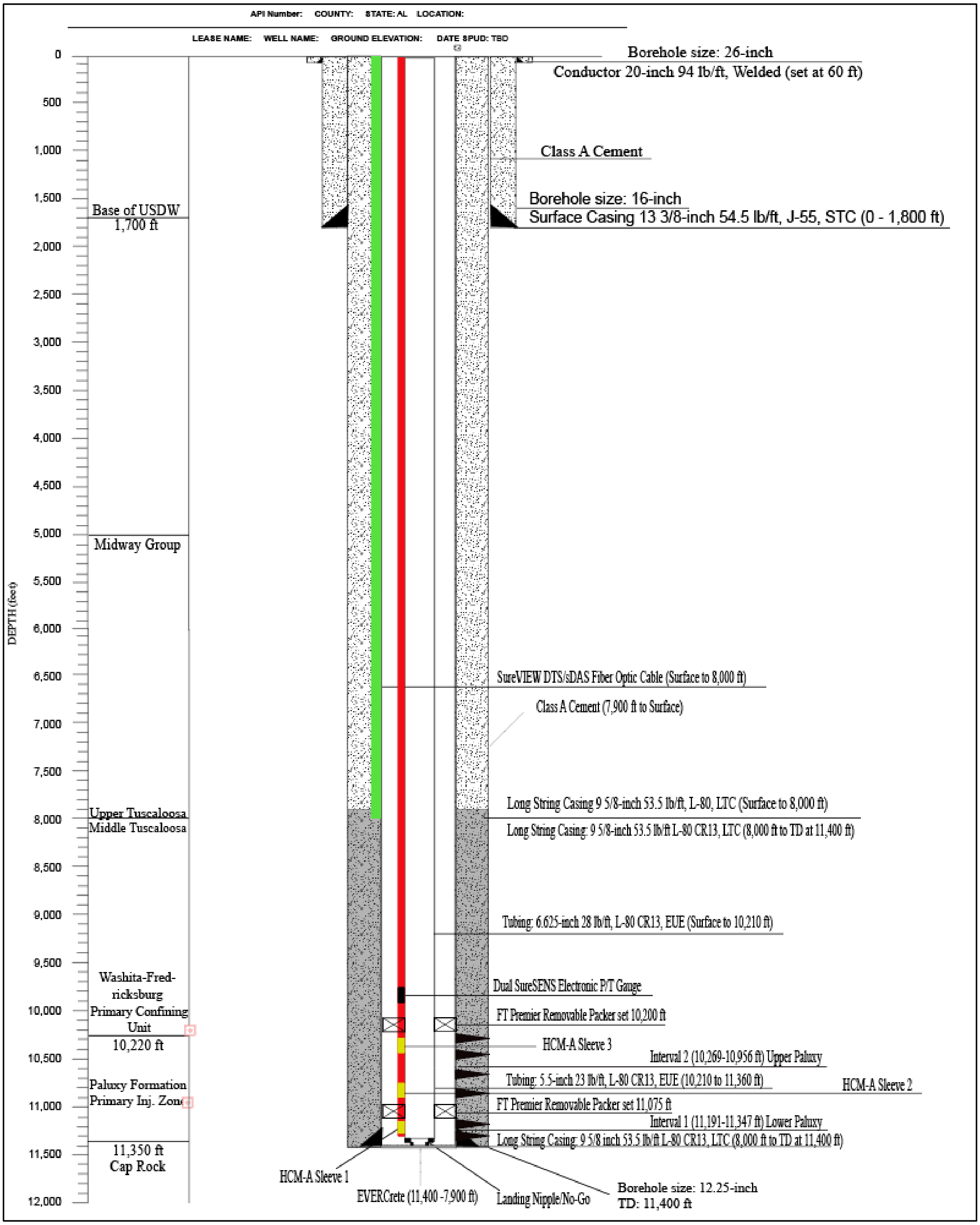

Figure 2. Injection Well Configuration, with Sliding Sleeves

B. Injection Well Tests

B.1. Tests or Measures for Determining Bottom-Hole Reservoir Pressure

Bottom-hole pressure measurements will be performed and recorded throughout the project. Pressure gauges will be placed in the injection tubing or in the deep casing string within the injection zone. These pressure-measurement devices will allow for continuous, real-time, surface readout of the pressure data. The bottom-hole reservoir pressure will be obtained using the final measurements from the pressure gauges in the injection zone after the CO_2 injection period has ended.

After the bottom-hole pressure is determined, a buffered fluid (brine) will be used to flush and fill the well to maintain pressure control of the well. The measured bottom-hole pressure will be used to determine the proper weight brine that should be used to stabilize the well. These data may also be used to determine the blend of cement to be used to plug the well (i.e., weight range of cement to prevent leak-off into formation or flowing of well, or to prevent premature setting and curing of the cement).

B.2 Testing Method to Ensure External Mechanical Integrity

The mechanical integrity of the well will be demonstrated after CO_2 injection and prior to the plugging of the well to ensure no communication has been established between the injection zone and the USDWs or ground surface (per 40 CFR 146.92(b)(2)). Such well integrity testing will use a temperature log, noise log, or an activated-oxygen log to be run in the well. A temperature log will be run over the entire depth of the injection well. Data from the logging run will be evaluated for anomalies in the temperature curve, which would be indicative of fluid migration outside of the injection zone. This data will also be compared to the information gathered from the baseline logs performed prior to injection of CO_2 into the well. Should deviations be noted between the temperature logs performed before and after the injection of CO_2 raise issues related to the integrity of the well casing or cement, this topic will be addressed promptly.

C. Plugging Plan

C.1 Procedures/Etc.

The methods and materials described in this part are based upon current understanding of the geology at the site and the current well designs. If necessary, the plan will be updated to reflect the latest well designs. Any changes to the plan will be submitted at least 60 days prior to the plugging of well and approved by EPA prior to commencing plugging activities. This plan also complies with Alabama Oil and Gas Board requirements in ASR 400-1-4-.14(1)-(2) that state:

> "A cement plug shall be placed across each hydrocarbon-bearing, abnormally pressured, or injection zone or a permanent-type bridge plug shall be placed at the top of each hydrocarbon-bearing zone or injection zone, but in either event a cement plug at least two hundred (200) feet in length shall be placed immediately above the uppermost hydrocarbon-bearing or injection zone. When the base of fresh water is penetrated, a cement plug at least two hundred (200) feet in length shall be placed at least fifty (50) feet below and shall extend to at least one hundred fifty (150) feet above the base of fresh water."

The following procedure includes operations to place a solid column of cement from the total depth of the well to the top of the casing string.

After the injection is terminated permanently, the injection tubing and packer will be removed. Then, the balanced-plug placement method will be used to plug the well. If, after flushing, the tubing and packer cannot be released, an electric line with tubing cutter will be used to cut off the tubing above the packer and the packer will be left in the well. The cement retainer method will be used for plugging the injection formation below the abandoned packer.

To further ensure no communication from the injection zone to the USDW zone or ground surface, the injection well casing will be plugged with cement.

Table 1 presents the intervals that will be plugged and the materials and methods that will be used to plug the intervals. The portion of the well corresponding to the injection zone will be plugged using Schlumberger's EverCRETE or similar CO_2-resistant cement with a retainer method. The cement retainer will be set 100 ft above the contact between the Paluxy Sandstone and the overlaying confining unit and will be constructed of corrosion-resistant materials. Approximately 220 sacks of CO_2-resistant cement will be used to plug the Paluxy injection interval (this includes a 10 percent excess volume to be squeezed through the perforations into the Paluxy Sandstone).

Table 1. Intervals to Be Plugged and Materials/Methods Used

Description	Top (ft)	Bottom (ft)	Type	Quantity
Lift 1	10,900	11,400	EverCRETE	220 sacks
Lift 2	10,400	10,900	EverCRETE	190 sacks
Lift 3	9,900	10,400	EverCRETE	190 sacks
Lift 4	9,400	9,900	EverCRETE	190 sacks
Lift 5	8,900	9,400	EverCRETE	190 sacks
Lift 6	8,400	8,900	EverCRETE	190 sacks
Lift 7	7,900	8,400	EverCRETE	190 sacks
Lift 8	7,400	7,900	Class A	190 sacks
Lift 9	6,900	7,400	Class A	190 sacks
Lift 10	6,400	6,900	Class A	190 sacks
Lift 11	5,900	6,400	Class A	190 sacks
Lift 11	5,400	5,900	Class A	190 sacks
Lift 13	4,900	5,400	Class A	190 sacks
Lift 14	4,400	4,900	Class A	190 sacks
Lift 15	3,900	4,400	Class A	190 sacks
Lift 16	3,400	3,900	Class A	190 sacks
Lift 17	2,900	3,400	Class A	190 sacks
Lift 18	2,400	2,900	Class A	190 sacks
Lift 19	1,900	2,400	Class A	190 sacks
Lift 20	1,400	1,900	Class A	190 sacks
Lift 21	900	1,400	Class A	190 sacks
Lift 22	400	900	Class A	190 sacks
Lift 23	0	400	Class A	155 sacks

The pressure used to squeeze the cement will be determined from the bottom-hole pressure data measured before beginning the plugging and abandonment process. A maximum pressure threshold of 90% of the determined reservoir fracture pressure for the Paluxy Sandstone will be utilized to constrain pressure increases during the cement injection process. If it appears that the injection pressure will exceed the 90% fracture pressure threshold and the total amount of cement has not been pumped into the injection zone, cement pumping will cease. Then, the tubing will be removed from the cement retainer to allow the pressure to return to static condition. After allowing the pressure to decline, the tubing will be re-strung through the cement retainer, and cement pumping will be attempted again. A rapid increase in pressure on the tubing would indicate that the Paluxy perforations have been sealed with cement, and no additional cement will be added to the zone or plug.

Cementing operations will continue to plug the entire wellbore. Cement will be pumped in 500 ft lifts (190 sacks) using a balance method. This will ensure efficient cement placement and prevent tubing from sticking in the cement column. **Figure 3** shows the details of the injection well after plugging and abandonment.

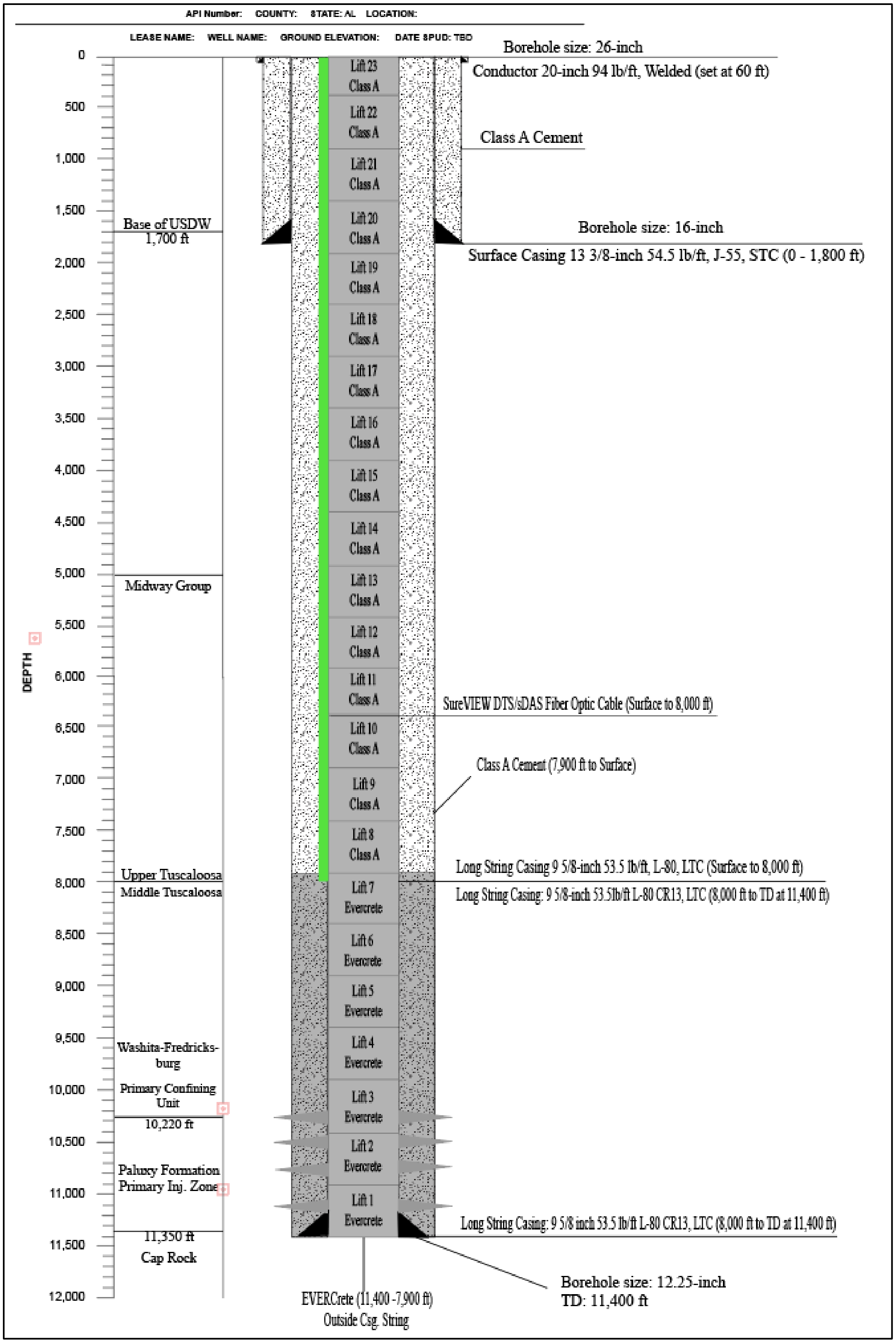

Figure 3. Diagram of the Injection Well After Plugging and Abandonment

After the remainder of the casing has been filled with cement, the casing sections will be cut off approximately 5 ft below surface and a steel cap will be welded to the top of the deep casing string. The cap will have the well identification number, the Class VI UIC well permit number, and the date of plug and abandonment inscribed on it. Soil will be backfilled around the well to bring the area around the well back to pre-well-installation conditions. This area will then be planted with natural vegetation.

C.2 OGB AL Documents and Forms

After the completion of the plugging activities, a plugging report (OGB AL Form OGB-11) will be submitted to the UIC Program Director, as well as the Alabama Oil and Gas Board, describing the methods and tests that were performed on the well during plugging. This report will be submitted to the UIC Program Director within 60 days of completing the plugging activities.

Longleaf CCS Hub

Longleaf CCS, LLC

Pre-Operational Testing Plan

40 CFR 146.82(a)(8), 146.87

Facility Information

Facility Name: Longleaf CCS Hub

Facility Contact: Longleaf CCS, LLC
14302 FNB Parkway
Omaha, NE 68154

Well Locations: Mobile County, Alabama

LL#1: Latitude: 31.071303° N
Longitude: -88.094703° W

LL#2: Latitude: 31.070774° N
Longitude: -88.074523° W

LL#3: Latitude: 31.0447129° N
Longitude: -88.0736318° W

LL#4: Latitude: 31.0569516° N
Longitude: -88.1047433° W

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List of Acronyms/Abbreviations

AoR	Area of Review
CCS	Carbon capture and storage
CO2	Carbon dioxide
CMG	Computer Modelling Group
DOE	Department of Energy
DAS	Distributed Acoustic Sensing
DTS	Distributed Temperature Sensing
EPA	Environmental Protection Agency
ERRP	Emergency and Remedial Response
ft	Feet
LL	Longleaf
mg/l	Milligrams per liter
MIT	Mechanical Integrity Test
MMcf/d	Million cubic feet/day
mol%	Percentage of total moles in a mixture made up by one constituent
msl	Mean sea level
mt	Metric tons
Mt	Millions of metric tons
mt/d	Metric tons per day
mt/y	Metric tons per day
MT/y	Millions of metric tons per year
PISC	Post-Injection Site Care
PNC	Pulsed Neutron Capture Log
ppmv	Parts per million volume
psi	Pounds per square inch, gauge
psia	Pounds per square inch, absolute
psi/ft	Pounds per square inch per foot
SS	Sub- Sea
TVD	True Vertical Depth

A. Overview of Pre-Operational Testing Plan

The Pre-Operational Testing Plan will be implemented to obtain the chemical and physical characteristics of the injection and confining zones and to meet the testing requirements of 40 CFR 146.87 and the well construction requirements of 40 CFR 146.86. The Pre-Operational Testing Plan will include a combination of logging, coring, formation hydrogeologic testing (e.g., a pump test and/or injectivity tests), and other activities during the drilling and construction of the proposed IOB#1 monitoring well and the LL#1 CO_2 injection well at the Longleaf CCS Hub project in Mobile County, Alabama (**Figure 1**).

The Pre-Operational Testing Plan will determine or verify the depth, thickness, mineralogy, lithology, porosity, permeability, and geomechanical information of the primary confining zone (Tuscaloosa Marine Shale), the secondary confining interval (Basal Shale of the Wash-Fred), and the injection interval (Paluxy Formation). In addition, formation fluid characteristics will be obtained from the Paluxy Formation to establish baseline data against which future measurements may be compared after the start of injection operations. The results of the testing activities will be documented in a report and submitted to the EPA within 60 days after the well drilling and testing activities have been completed.

Longleaf CCS, LLC will take core and acquire logs from the IOB#1 monitoring well located about 2 miles north of the LL#1 injection well. Longleaf CCS, LLC will bypass taking whole core from the LL#1 injection well. Based on previous coring experience within the Paluxy at the Anthropogenic Test CO_2 demonstration at Citronelle, drilling whole intervals would increase the likelihood of enlarged wellbore as the processes associated with drilling and collecting core require circulation of drilling fluids for long periods of time. These expanded well diameter sections, called washouts, present challenges to well cementing.

Similarly, injection-falloff testing would be conducted in the IOB#1 monitoring well. These tests are used to determine reservoir and confining unit fracture gradients. Detailed geomechanical information gained from core and log analysis will be input into a 1-dimensional Mechanical Earth Model (1-D MEM) to provide understanding of formation mechanical properties and fracture gradients of the Paluxy reservoir and its surrounding confining units.

Longleaf CCS, LLC will rely on information from geologic and petrophysical tests in the IOB#1 monitoring well to satisfy the Class VI rule requirements for drilling and constructing injection wells at the Longleaf CCS Hub. Longleaf CCS, LLC will use the Tuscaloosa Marine Shale, Basal Wash-Fred Shale, and Paluxy Formation whole and/or sidewall core samples collected from the IOB#1 monitoring well to satisfy the requirement of 40 CFR 146.87(b) for the proposed LL#1 injection well (**Figure 1**). Additional details are provided in the subsequent sections of this plan to describe the rationale for opting to forego coring and fracture testing activities in the proposed LL#1 injection well.

Three more injection wells (LL#2, LL#3, and LL#4) are planned to be drilled at the Longleaf CCS Hub, with each well approximately 2 miles from the LL#1 injection well (**Figure 1**)**.** Testing for the LL#2, LL#3, and LL#4 will be identical to the LL#1 except for the collection of sidewall cores and fluid samples, which will be done only in the LL#1.

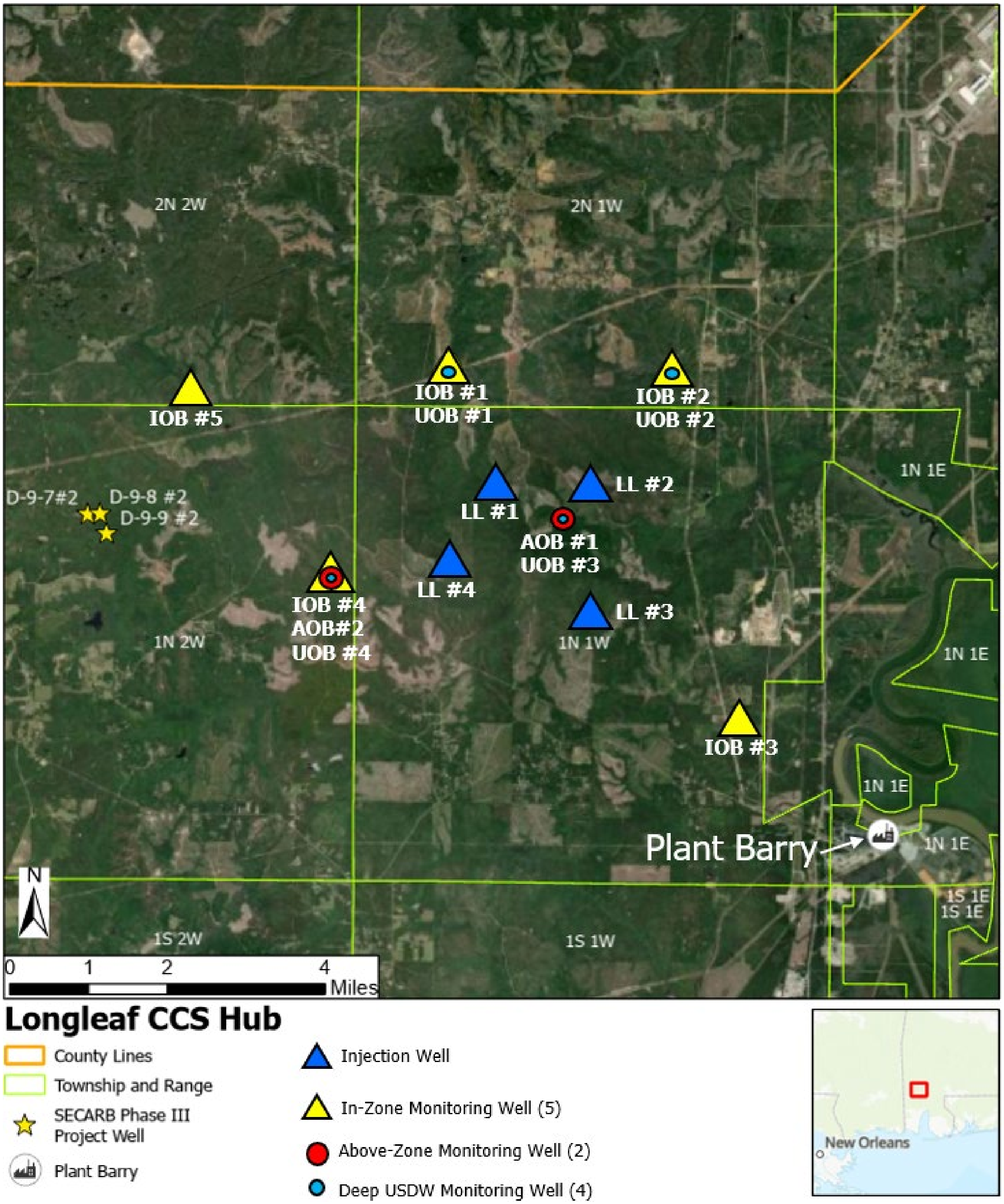

Figure 1: Locations of Proposed Injection and Monitoring Wells at the Longleaf CCS Hub

B. Wireline Logging

Open-borehole logs will be collected in the LL#1 injection well to obtain in-situ structural, stratigraphic, physical, chemical, and geomechanical information for the confining zones and the injection zone. Logs, surveys, and tests will be used to ensure conformance with the injection well construction requirements according to 40 CFR 146.86 and establish accurate baseline data for future comparison. Open-borehole characterization logs will be obtained after reaching the surface casing point and the long-string casing point (i.e., total borehole depth) in the vertical borehole. Open-borehole wireline logs will not be run in the 30-in.-diameter conductor casing borehole because logging tools are not suited for this large-diameter hole size (**Figure 2**).

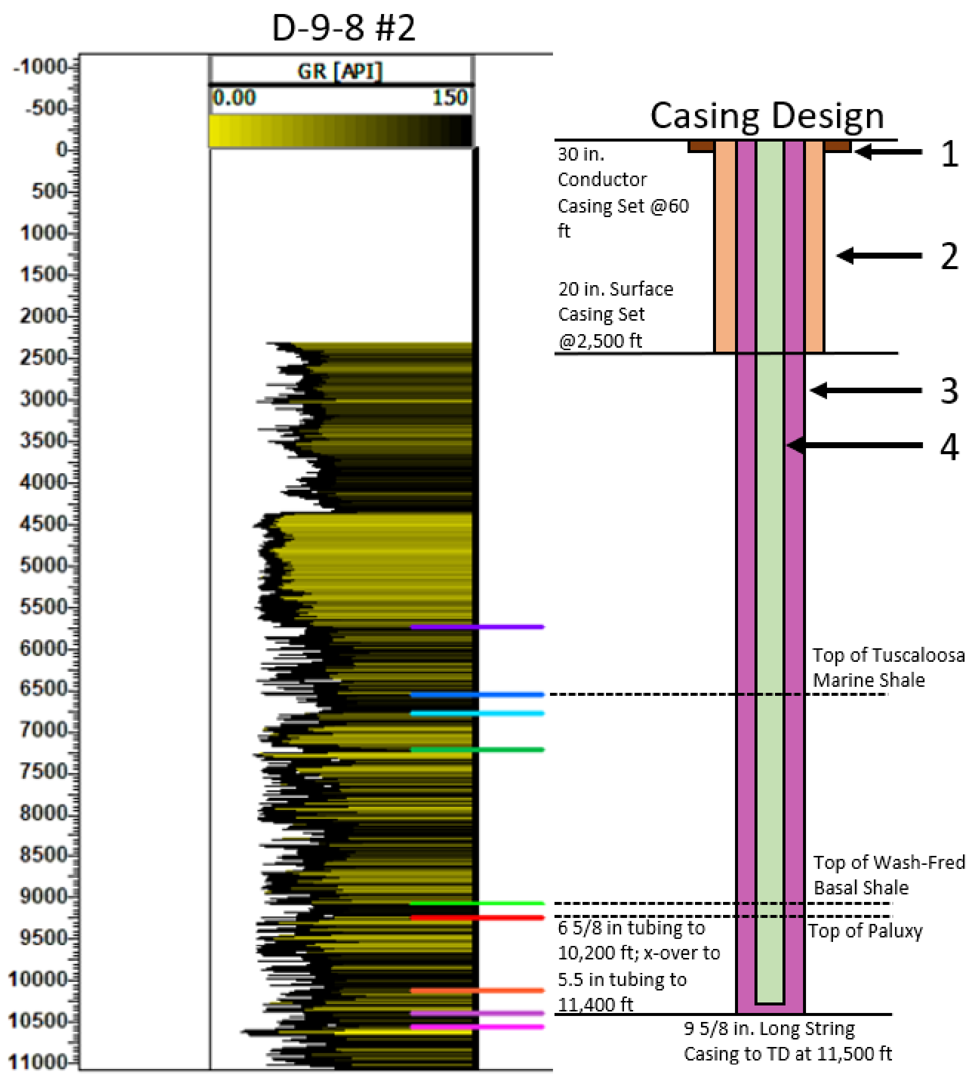

Figure 2. Casing intervals for the LL#1. 1) Conductor 2) Surface 3) Long-string 4) Tubing. Note: Depths in D-9-8 #2 log shown are 1,000 ft up dip from the LL#1 injection well.

A description of each logging method that Longleaf CCS, LLC will include in its logging program at the LL#1 injection and the IOB#1 monitoring well follows:

Open Hole Logs

- **Geologic Description (Mud Log)** – Provides a continuous visual description of the drill cuttings-based lithology of the formations as the well is drilled. Physical cuttings sample datasets are typically collected and cataloged every 20-50 ft for future assessment. Mud logs are also used to evaluate any hydrocarbon or natural gas shows encountered while drilling the well.

- **Triple Combination** – Includes gamma-ray/spontaneous potential, porosity, and resistivity logs.

- **Acoustic Scanning Log (i.e., Dipole Sonic)** – This acoustic log measures elastic properties axially, radially, and azimuthally to support geomechanical, geophysical, fractures, and petrophysical modeling. Furthermore, sonic logs like compressional sonic (DT) can be used along with density logs for preparing synthetic seismic logs.

- **Formation Micro Imager** – Provides micro-resistivity formation images when using water-based mud. Borehole images can reveal bedding planes and associated contacts, fractures (open, healed, and induced), and reservoir textures (sedimentary structures). A multi-arm caliper run with this tool provides information on hole shape and is used for subsurface stress analysis. The tool also provides borehole inclination and azimuthal information which complement the deviation check surveys taken while drilling the well.

- **High-Definition Nuclear Magnetic Resonance** – This log provides nuclear magnetic resonance (NMR) measurements of the buildup and decay of the polarization of hydrogen nuclei (protons) in the liquids contained in the pore space of rock formations. One key measurement provided by this log is the total formation porosity. Permeability and effective porosity can be estimated from the free-fluid to bound-fluid ratio and the pore-size distribution. NMR measurement can also be used for fluid identification because this log also provides a hydrogen index measurement.

- **Pulsed Neutron Spectroscopy** – This logging tool is used for measurements and definitions of mineralogy and matrix properties of injection and confining zones. The data from spectroscopy logging can be used to estimate mineral-based permeability, determine well-to-well correlations from geochemical stratigraphy, and determine sigma matrix for case hole and open hole sigma saturation analysis, among others. Elemental analysis or similar processing of these logs yields the volumetric proportions of mineral composition and pore fluids. For example, these logs can reveal the relative proportions of clay minerals, quartz, calcite, and fluid volume in the formation.

- **Wireline Formation Testing** – This wireline tool suite has the capacity to collect reservoir pressure measurements, static fluid levels and fluid samples that can be kept at formation pressures representative of downhole conditions. The tool can also be run to conduct a *mini-frac* test. These tests provide fracture pressure estimates and far field stress directions (in conjunction with the formation micro imager). Wireline test data can be used as calibration for other stress measurements (sonic logs).

Cased Hole

- **Ultrasonic Imaging Tool** – This log can provide estimates of well integrity and zonal isolation through measurement of cement acoustic impedance. The information from this log can be used to create maps of the casing integrity and cement, to identify corrosion or casing damage, and determine if there is solid (cement), liquid, or gas in between the casing and formation. Modern acoustic cement-evaluation tools, such as ultrasonic logs, are comprised of monopole (axisymmetric) transmitters (one or more) and receivers (two or more). They operate on the principle that acoustic amplitude is rapidly attenuated in good cement bond but not in partially bonded or free pipe. The ultrasonic tool can also provide a casing thickness interpretation.

- **Cement Bond Log (CBL)** – CBL tools use sonic waves to interrogate the integrity of the well's cement. CBLs use acoustic transmitters and receivers to measure signal attenuation to provide a measure of how well the casing and the cement are bonded. CBLs provide an indication of the cement-to-formation bond in the form of a variable density log. Typically, CBLs provide an average measurement but they can also provide maps where logging tools with multiple transmitters and receivers on pads are used.

- **Temperature Logging Surveys** – The temperature log provides a subsurface temperature profile necessary for characterizing in situ conditions. Temperature logging is used to identify the top of cement after cementing to help ensure wellbore integrity.

See **Table 1** for a list of the various Surface and Long String Casing wireline logging tools that will be deployed in the LL#1, LL#2, LL#3, and LL#4. **Table 2** lists the various Surface and Long String Casing wireline logging tools that will be deployed in the IOB#1 well.

Table 1: Wireline Logging Program for LL#1, LL#2, LL#3, and LL#4

Depth Interval (ft)	Log	Purpose/Comments
Surface Casing		
0 – 2,500	Mudlog	Monitor and ensure uninterrupted drilling process as well as provide lithologic information while drilling
0 – 2,500	SP/Resistivity	Characterize basic geology (Lithology, formation tops)
0 – 2,500	Cement Bond Log	Evaluate cement integrity
Long String Casing		
2,500 – 11,500	Mudlog	Monitor and ensure an uninterrupted drilling process as well as provide lithologic information while drilling
2,500 – 11,500	Temperature Log	Determine natural geothermal gradient outside well for comparison to future temperature logs for external mechanical integrity evaluations. Baseline log is run a minimum of 30 days after drilling and casing/ cementing the well because temperature anomalies due to circulation of drilling fluid and/or open-borehole injection testing will persist for several weeks to months.
2,500 – 11,500	Borehole Profile/Caliper	Evaluate borehole condition prior to cementing
2,500 – 11,500	Nuclear Magnetic Resonance Tool	Enhanced characterization of geologic and geomechanical properties that control injectivity and caprock/seal integrity.
2,500 – 11,500	Triple Combination/ Pulsed Neutron Spectroscopy	Characterize basic geology (Gamma Ray, Resistivity, Porosity, Mineralogy)
2,500 – 11,500	Formation Micro Imager	Enhanced characterization of geologic and geomechanical properties that control injectivity and caprock/seal integrity.
2,500 – 11,500	Dipole Sonic	Determine the reservoir fracture pressure gradient and geomechanical properties of the confining and injection zones
2,500 – 11,500 (cased hole)	Cement Bond log/Ultrasonic/Temperature	Evaluate cement integrity, internal and external casing condition

Table 2: Wireline Logging Program for IOB#1 Well

Depth Interval (ft)	Log	Purpose/Comments
	Surface Casing	
0 – 2,500	Mudlog	Monitor and ensure uninterrupted drilling process as well as provide lithologic information while drilling
0 – 2,500	SP/Resistivity	Characterize basic geology (Lithology, formation tops)
0 – 2,500	Cement Bond Log	Evaluate cement integrity
	Long String Casing	
2,500 – 11,500	Mudlog	Monitor and ensure an uninterrupted drilling process as well as provide lithologic information while drilling
2,500 – 11,500	Temperature Log	Determine natural geothermal gradient outside well for comparison to future temperature logs for external mechanical integrity evaluations. Baseline log is run a minimum of 30 days after drilling and casing/ cementing the well because temperature anomalies due to circulation of drilling fluid and/or open-borehole injection testing will persist for several weeks to months.
2,500 – 11,500	Borehole Profile/Caliper	Evaluate borehole condition prior to cementing
2,500 – 11,500	Nuclear Magnetic Resonance Tool	Enhanced characterization of geologic and geomechanical properties that control injectivity and caprock/seal integrity.
2,500 – 11,500	Triple Combination/ Pulsed Neutron Spectroscopy	Characterize basic geology (Gamma Ray, Resistivity, Porosity, Mineralogy)
2,500 – 11,500	Formation Micro Imager	Enhanced characterization of geologic and geomechanical properties that control injectivity and caprock/seal integrity.
2,500 – 11,500	Dipole Sonic	Determine the reservoir fracture pressure gradient and geomechanical properties of the confining and injection zones
Selected Injection and Confining Zone Points	Wireline Testing	Injection and confining zone mechanical properties (fracture pressure), reservoir fluid samples, reservoir pressure and static fluid level.
2,500 – 11,500 (cased hole)	Cement Bond log/Ultrasonic/Temperature	Evaluate cement integrity, internal and external casing condition

C. Coring

Longleaf CCS, LLC will attempt to collect 60 ft. or more of 4-inch whole core from both the Paluxy Formation (injection interval) and the Tuscaloosa Marine Shale (primary confining unit) while drilling the first Longleaf CCS Hub monitoring well, the IOB#1. Additional whole core may also be taken from the Wash-Fred and Lower Tuscaloosa sandstones to evaluate the potential for future storage opportunities. Due to the risk of wellbore washouts, Longleaf CCS, LLC will forego collecting whole core in the LL#1 injection well. Instead, Longleaf CCS, LLC will attempt to collect approximately 50 rotary sidewall cores in the LL#1 injection well. The planned distribution of these 50 sidewall cores is provided in **Table 3**.

These whole and sidewall cores will be preserved on site and then shipped to a commercial core testing/analysis laboratory for analysis. Properties analyzed will include routine core analysis (porosity, permeability, grain density and residual fluid saturation). Specialized core analysis, including X-ray diffraction (XRD) for mineralogical analysis, and capillary pressure will be conducted on selected whole core samples. If the wireline formation tests fail to determine injection and confining zone mechanical properties, core plug mechanical property tests (e.g. triaxial tests) may be conducted to determine these properties and to estimate fracture pressure. The wireline and/or core mechanical property results will be used to calibrate wireline logs.

Table 3: Planned Sidewall Core Collection by Formation in the LL#1 Injection Well

Formation	# of Core Plugs
Upper Tuscaloosa/Eutaw	5
Tuscaloosa Marine Shale	5
Lower Tuscaloosa Massive Sand	5
Wash-Fred	15
Paluxy	20
TOTAL	50

D. Fluid Sampling

The analysis of reservoir fluid samples will be used to satisfy the requirement of 40 CFR 146.87(5)(c) and ensure that baseline geochemical properties are established for the Paluxy Formation across the AoR for the Longleaf CCS Hub. Longleaf CCS, LLC will collect fluid samples from the LL#1 injection well for the Paluxy Formation. Any fluids introduced into the formation during drilling, borehole conditioning, cementing, perforation acid treatment, and/or formation (injection) testing would first need to be removed before representative formation fluid samples can be collected. Consequently, Longleaf CCS, LLC will attempt to collect fluid samples during the active drilling phase using a Wireline Formation Testing tool rather than collect samples after well completion. The in-zone fluid samples from the LL#1 injection well will be collected using a formation testing tool while the hole is open. If fluid samples cannot be taken via the formation testing tool, fluid samples can be collected after well completion by swabbing fluid or pumping through tubing with a packer set just above the perforated interval. After an appropriate volume of fluid is swabbed from the well, samples can be taken via a slickline deployed tool, such as a Kuster Flow Through Sampler (FTS). Both of these fluid sampling methods will sample reservoir pressure and static fluid levels.

The analytic and field parameters for fluid sampling are presented in **Table 4**. These parameters are consistent with the fluid sampling analysis and processes that are detailed in the ***Testing and Monitoring Plan*** and the ***Quality Assurance Surveillance Plan*** associated with this permit. Longleaf CCS, LLC will also collect hydrogeologic data from the extensive wireline program, as discussed in Section B of this plan.

Table 4: Summary of Analytical and Field Parameters for Fluid Sampling in the Paluxy Formation Injection Interval

Parameters	Analytical Methods
Paluxy Formation (Injection Interval)	
Cations: Al, Ba, Mn, As, Cd, Cr, Cu, Pb, Sb, Se, and Tl	ICP-MS, EPA Method 6020
Cations: Ca, Fe, K, Mg, Na, and Si	ICP-OES, EPA Method 6010B
Anions: Br, Cl, F, NO_3 and SO_4 Dissolved CO_2	Ion Chromatography, EPA Method 300.0 Coulometric titration, ASTM D513-11
Total Dissolved Solids Water Density Alkalinity pH (field) Specific conductance (field) Temperature (field)	Gravimetry, APHA 2540C Oscillating body method APHA 2320B EPA 150.1 APHA 2510 Thermocouple

E. Mechanical Integrity Testing

Longleaf CCS, LLC will conduct tests and run logs as needed to demonstrate the internal and external mechanical integrity of the injection well prior to initiating CO_2 injection, satisfying the hydrogeologic testing requirements under 40 CFR 146.87(e). Internal mechanical integrity refers to the absence of leaks in the tubing, packer, and casing above the packer. External mechanical integrity refers to the absence of fluid movement/leaks through channels adjacent to the injection wellbore that could result in fluid migration into an USDW.

Prior to drilling out the plug on each casing string, a casing pressure test will be conducted. The test will be designed not to exceed the rated pressure of the casing. Based on State of Alabama Oil and Gas Board guidance, surface casing should be tested at 1,500 psi for wells deeper than 9,000 ft TVD. Long string casing will be tested at 1,500 psi or 0.2 psi/ft, not to exceed 1,500 psi [1].

If a decline in pressure greater than 10% within the first 30 minutes of testing is noted, or if other indications of a leak are indicated, then the casing string will be recemented or repaired, or have an additional casing string run. Once remedial measures have taken place, the pressure test will be conducted again. After cementing the casing strings, drilling will not commence until a time lapse of 12 hours under pressure has passed. All casing pressure tests will be recorded in the driller's log[1].

After the proposed injection well LL#1 is completed, including the installation of tubing, packer, and annular fluid, a test of the well's internal mechanical integrity will be performed by conducting a standard annular pressure test (SAPT). Class VI regulations do not define a pressure that the test is run. EPA Region 4 requires an annular pressure test of 300 psig for Class II wells, and we propose to use that value here. The annular pressure test is a short-term test wherein the fluid in the annular space between the tubing and casing is pressurized, the well is shut-in (temporarily sealed up), and the pressure of the annular fluid is monitored for leak-off.

The planned procedure will be to provide a comparison of the pressure change throughout the test period to 3% of the test pressure (0.03 × test pressure). If the annulus test pressure decreases by this amount or more, the well has failed to demonstrate internal mechanical integrity. If the annulus pressure changes by less than 3% during the test period, the well has demonstrated internal mechanical integrity. If the well fails the annular pressure test, the tubing and packer will be removed from the well to determine the cause of the leak. During the active CO_2 injection phase, internal mechanical integrity will be continuously monitored by the well annular pressure maintenance and monitoring system, as discussed in more detail in the ***Testing and Monitoring Plan***.

Longleaf CCS, LLC will also employ various methods to demonstrate external mechanical integrity upon the completion of the proposed CO_2 injection well LL#1 and prior to the start of injection operations. Longleaf CCS, LLC will run pulsed neutron

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[1] State Oil & Gas Board of Alabama Administrative Code Oil and Gas Report 1. *Rules and Regulations Governing the Conservation of Oil and Gas in Alabama. Rule 400-1-4-.09. Casing, Cementing, and Test Pressure Requirements.*

capture and temperature logs on the completed injection well in order to demonstrate external mechanical integrity, with these logs also providing supporting hydrogeologic data discussed in Section G. Longleaf CCS, LLC will run an Ultrasonic Imaging Tool to test cement integrity and provide additional confidence that there are no pathways for potential CO_2 or brine migration through the wellbore, casing, or cement prior to injection operations, satisfying the requirement of 40 CFR 146.87(a)(4).

F. Fracture Pressure of Injection and Confining Zones

As discussed above, the LL#1 injection well will be drilled and completed with limited testing after open hole logs are gathered. This will help limit borehole rugosity and provide the highest probability of achieving a mechanically sound cement job. As such, Longleaf CCS, LLC will not plan on completing an open-hole fracture pressure test in the LL#1. As the alternative, prior to installing the long-string casing in the IOB#1 monitoring well, Longleaf CCS, LLC will use the formation testing tool in the IOB#1 monitoring well to conduct formation fracture tests to measure the fracture pressure of the injection formation and the confining unit(s). Then, a *minifrac test* will be used to locally pressure up a small interval in the test formation to the point where it just starts to fracture. This provides the fracture pressure without causing significant damage to the formation being tested.

In addition, to fully satisfy the requirements of 40 CFR 146.87(d), Longleaf CCS, LLC intends to run a dipole sonic log (Stoneley wave analysis) in the LL#1 injection well which will enable calculation of the reservoir fracture pressure of the injection zone and the confining zone.

G. Hydrogeologic Testing

After the LL#1 injection well is completed, including perforating the injection interval and installing the injection tubing and packer, Longleaf CCS, LLC intends to run an injection test on the Paluxy Formation to determine the large-scale composite injectivity (transmissivity) of the injection interval and possible presence of nearby hydrogeologic boundaries (**Table 5**). Longleaf CCS, LLC intends to use the extensive wireline logging program to support and corroborate the hydrogeologic properties that are collected via direct fluid sampling from the injection zone. Additionally, Longleaf CCS, LLC will collect reservoir pressure from the Paluxy Formation in the LL#1 injection well as a result of the injectivity test.

Table 5: Composite Injectivity Evaluation Testing Program

Test	Description	
Paluxy Formation Composite Injectivity Evaluation	Objectives	**Primary objective:** To determine the large-scale transmissivity of the Paluxy Formation and possible presence of nearby hydrogeologic boundaries and provide direct information about the injectivity potential of the Paluxy Formation or a selected portion of it.
	Test/Depth Zone	The Paluxy Formation. Approximate depth interval 10,220-11,350 ft measured depth (upper Paluxy). Alternatively, this test may be conducted on one or more discrete depth intervals within the Paluxy Formation.
	Test Activity/ Summary	The injection tubing and packer would be set just above the top of the Paluxy Formation inside the casing string. After the packer is in place, a constant-rate injection utilizing produced or inhibited fluid will be conducted. At the end of injection the recovery pressure for the composite zone will be monitored for a period approximately 1.5 times or more of the injection period.

A pre-operation injection and pressure fall-off test will serve as the baseline test for establishing reservoir and well conditions for comparison to results of subsequent pressure fall-off tests conducted during the operational period (i.e., during CO_2 injection). Specifically, this comparison is intended to confirm that the pressure increase within the injection interval is less than that predicted and ensure that the modeled parameters used in the ***Area of Review and Corrective Action Plan*** modeling analysis represent actual conditions[2].

The guidelines of EPA Region 6[3] defines a pressure fall-off test as a pressure transient test that consists of shutting in an injection well after a period of prolonged injection and measuring the pressure fall-off. Longleaf CCS, LLC will follow this practice for the Longleaf CCS Hub. The fall-off period is a replay of the injection test preceding it; consequently, it is affected by the magnitude, length, and rate fluctuations of the injection

[2] EPA (U.S. Environmental Protection Agency). 1990. Ambient Pressure Monitoring. EPA Region 5, Regional Guidance #6. Washington, D.C.

[3] EPA (U.S. Environmental Protection Agency). 2002. EPA Region 6 UIC Pressure Falloff Testing Guideline. Washington, D.C.

period. Fall-off testing analysis provides reservoir and well parameters, including transmissivity, storage capability, skin factor, and well flowing and static pressures. Establishing a baseline value for these parameters will be useful for identifying changes in the well and/or reservoir properties after CO_2 injection begins; for example, an increasing skin factor may be indicative of formation damage which signals a need for well remediation while a decreasing skin factor may indicate near-wellbore cleanup.

The baseline pressure fall-off test will be conducted as part of the post-completion injectivity testing (e.g., constant-rate injection test conducted as either a single-well test and/or multi-well interference test) discussed in the following section. Guidance for conducting the pressure fall-off test in this project is provided by EPA Region 5 [4] [5]. In general, the recommendations provided in these guidance documents will be followed to the extent practicable. If circumstances dictate steps are required outside of the guidance provided, the proposed operations plan will be cleared with the UIC Program Director prior to initiation.

H. Stimulation Program

The need for stimulation to enhance the injectivity potential of the Paluxy Formation is not anticipated. Modeling based on data collected from the geologic site characterization, and the experience gathered from the Anthropogenic Test CO_2 injection demonstration at Citronelle, has concluded that the injection interval is of high quality due to the relatively high porosity and permeability of the Paluxy reservoir. More information regarding the reservoir properties can be found throughout the ***Application Narrative****.* If there is a need to bypass near-wellbore drilling damage, perforations may be flushed with a diluted acid mixture. To further ensure the acid cleans all perforations, soluble perf balls may be pumped to divert fluid. These perf balls temporarily seal perfs, then dissolve completely to leave clear access to the formation. In the unlikely event stimulation techniques are needed to bypass any drilling induced damage, the well stimulation plan

[4] EPA (U.S. Environmental Protection Agency). 1990. *Ambient Pressure Monitoring*. EPA Region 5, Regional Guidance #6. Washington, D.C.

[5] EPA (U.S. Environmental Protection Agency). 1998. Planning, Executing, and Reporting Pressure Transient Tests. EPA Region 5 – Underground Injection Control Section Regional Guidance #6. Washington D.C.

will be submitted to EPA Region 4 for review and approval prior to commencing these operations.

I. Schedule

Longleaf CCS, LLC will provide the UIC Program Director with the opportunity to witness all logging and testing by this subpart. Pursuant to 40 CFR 146.87(f), Longleaf CCS, LLC will submit a schedule of such activities to the UIC Program Director 30 days prior to conducting the first test and submit any changes to the schedule 30 days prior to the next scheduled test. The scheduled testing will be developed within 90 days following the permission for the construction of the proposed injection well.

J. Reporting

Longleaf CCS, LLC will provide the EPA with a descriptive report(s) prepared by knowledgeable analyst(s) that includes an interpretation of the results of the casing and cement integrity, well logging, well testing, and core data. These report(s) will include:

- The date and time of each pressure test, the date of well bore completion, and the date of installation of all casings and cements, including chart results and interpretations of each cement bond log, cement pressure tests, and any supplemental well data,
- Interpretation of the well logs by a log analyst, including any assumptions, determination of porosity, permeability, lithology, thickness, depth, and formation fluid salinity of relevant geologic formations, and any changes in interpretation of site stratigraphy based on formation testing logs,
- Interpretation of whole and/or sidewall core analysis results, including any changes in interpretation of site stratigraphy based on core analysis, analytical methods, quality assurance information, tabular and/or graphic data, and photographs,
- Reservoir fluid sampling results, including descriptions of the sampling equipment, sampling methodology, sample preservation methods, field and laboratory results, and any changes in interpretation of site stratigraphy based on fluid sample results,
- Reservoir pressure results and geomechanical results to determine injection and confining zone fracture pressure, including type and location of pressure gauge,

type of flow meter and calibration records, raw pressure and flow data, and plot of flow rate versus pressure data, and any changes in geomechanical interpretations based on test results, and

- Hydrogeologic test results, including pressure and flow data, testing parameters, discussion of results, and any changes in interpretation of injectivity and storage potential based on injection/falloff test results.

Longleaf CCS Hub

Longleaf CCS, LLC

Testing and Monitoring Plan and Reporting

40 CFR 146.90, 40 CFR 146.91

Facility Information

Facility Name: Longleaf CCS Hub

Facility Contact: Longleaf CCS, LLC
14302 FNB Parkway
Omaha, NE 68154

Well Locations: Mobile County, Alabama

LL#1: Latitude: 31.071303^{o} N
Longitude: -88.094703^{o} W
LL#2: Latitude: 31.070774^{o} N
Longitude: -88.074523^{o} W
LL#3: Latitude: 31.0447129^{o} N
Longitude: -88.0736318^{o} W
LL#4: Latitude: 31.0569516^{o} N
Longitude: -88.1047433^{o} W

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List of Acronyms/Abbreviations

AoR	Area of Review
CCS	Carbon capture and storage
CO_2	Carbon dioxide
CMG	Computer Modelling Group
DOE	Department of Energy
DAS	Distributed Acoustic Sensing
DTS	Distributed Temperature Sensing
EPA	Environmental Protection Agency
ERRP	Emergency and Remedial Response
ft	Feet
LL	Longleaf
mg/l	Milligrams per liter
MIT	Mechanical Integrity Test
MMcf/d	Million cubic feet/day
mol%	Percentage of total moles in a mixture made up by one constituent
msl	Mean sea level
mt	Metric tons
Mt	Millions of metric tons
mt/d	Metric tons per day
mt/y	Metric tons per day
MT/y	Millions of metric tons per year
PISC	Post-Injection Site Care
PNC	Pulsed Neutron Capture Log
ppmv	Parts per million volume
psi	Pounds per square inch, gauge
psia	Pounds per square inch, absolute
psi/ft	Pounds per square inch per foot
SS	Sub- Sea
TVD	True Vertical Depth
UIC	Underground Injection Control
USDW	Underground Source of Drinking Water

A. Overview of Testing and Monitoring Plan and Strategy

This Testing and Monitoring Plan is designed to ensure that injection and storage of CO_2 at the Longleaf CCS Hub is done safely, without endangerment to local USDWs or communities, and satisfies the requirements under 40 CFR 146.90.

Data collected during the implementation of this Plan will be used to confirm that injection procedures are operating as planned, that USDWs are protected, and that the CO_2 plume and pressure front are developing as predicted. The monitoring data will also be used to validate and update geologic and reservoir simulation models.

A key tenant of this Plan is deployment of well-based direct and indirect monitoring. Direct monitoring methods (pressure, flow rate, fluid sampling etc.) will be paired with indirect monitoring methods (fiber optic sensing, vertical seismic profiles, pulsed neutron capture logs, etc.) at a network of monitoring wells. This Plan is designed to incorporate monitoring using four injection wells (LL#1, LL#2, LL#3, and LL#4) and the series of monitoring wells constructed in the Longleaf CCS Hub storage area.

To protect USDWs and comply with 40 CFR 146.90, Longleaf CCS, LLC will construct a well-based testing and monitoring network that includes five types of wells. These five types of wells are listed below with their monitoring objective(s), their stratigraphic location, their approximate depth, and the number of each to be completed. **Figure 1** is a map of the Longleaf CCS Hub with the geographic locations of these monitoring wells. **Figure 2** is a stratigraphic column of the Longleaf CCS Hub site geology describing the stratigraphic location of each type of monitoring well.

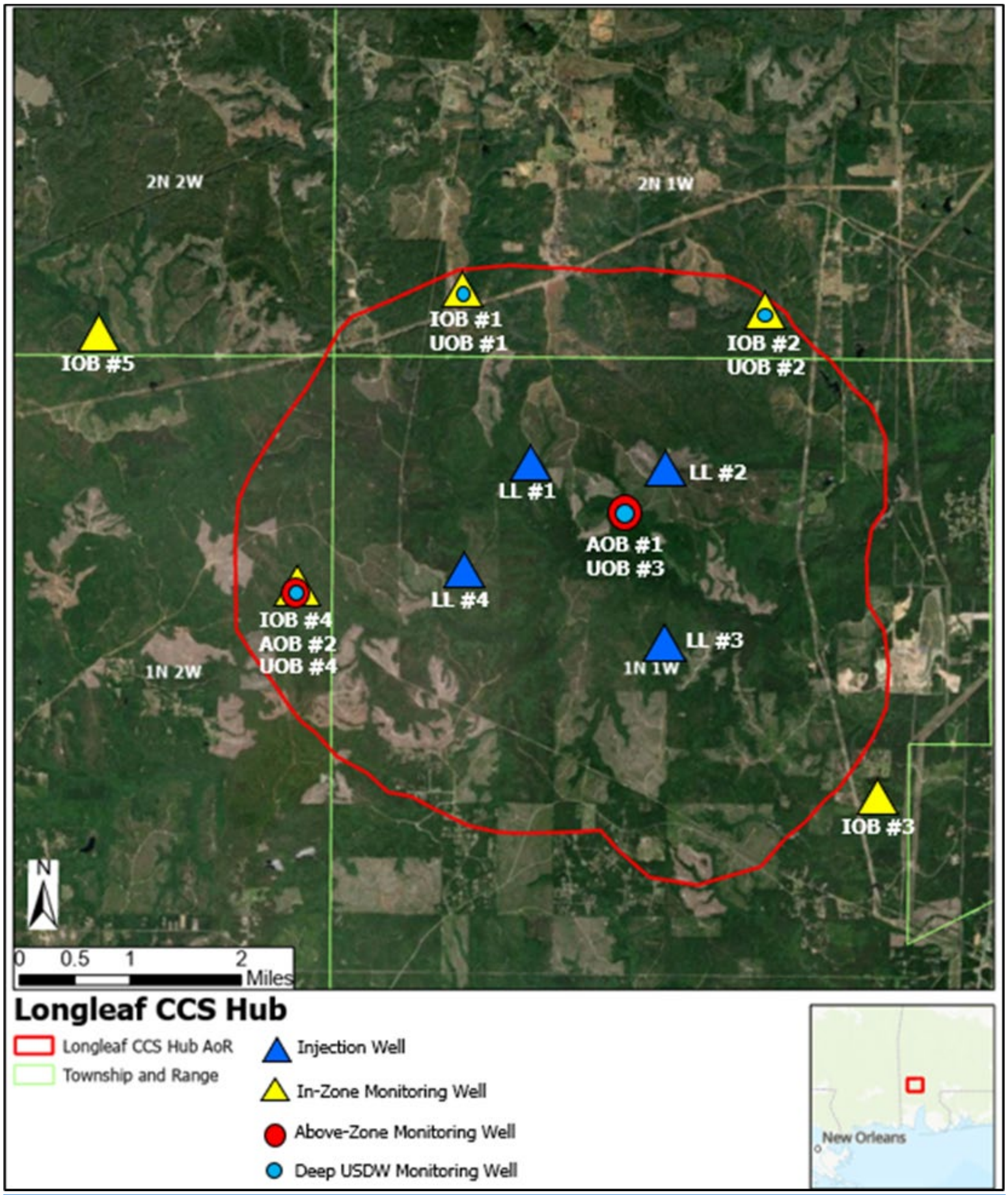

Figure 1: Locations of Proposed Injection and Monitoring Wells at the Longleaf CCS Hub.
Note: Shallow ground water monitoring wells are located on each well pad (10 total).

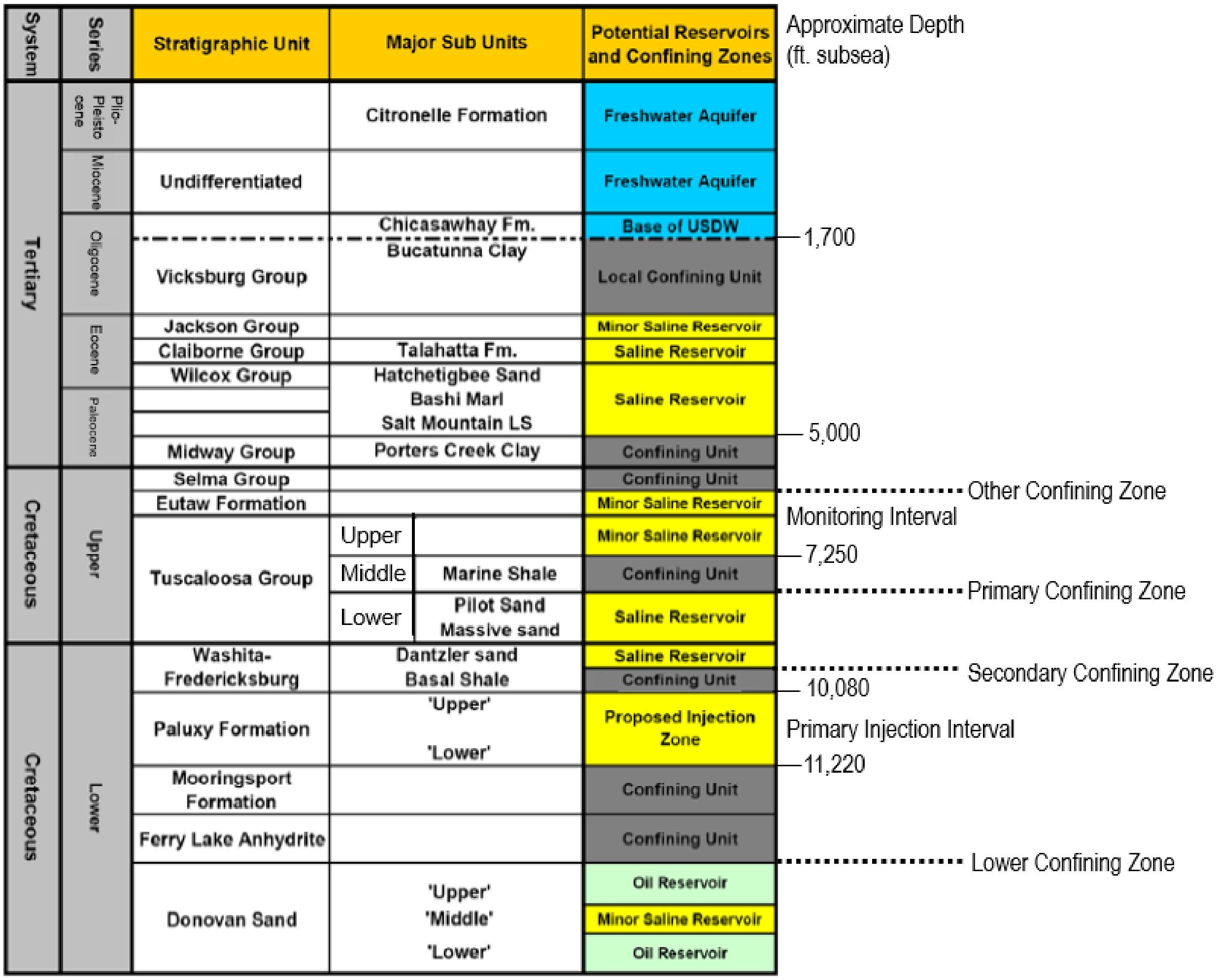

Figure 2: Geologic Stratigraphic Column at the Longleaf CCS Hub (modified from Pashin et al., 2008).[1]

Injection Wells

- Monitoring Objectives: Monitor CO_2 plume, pressure, injection process, and geophysical environment.
- Stratigraphic location: Paluxy Formation. Approximate depth of 10,100 ft MSL to top of Paluxy Formation.

[1] Pashin, J. C, McIntyre, M. R., Grace, R. L. B., Hills, D. J., "Southeastern Regional Carbon Sequestration Partnership (SECARB) Phase III, Final Report", Report to Advanced Resources International by Geological Survey of Alabama, Tuscaloosa, September 12, 2008

- Number to be completed: Four total injection wells for the Longleaf CCS Hub. See additional permits for other injection wells.

In-Zone Monitoring Wells

- Monitoring Objectives: Monitor CO_2 plume, pressure, and geophysical environment.
- Stratigraphic location: Paluxy Formation. Approximate depth of 10,100 ft MSL to top of Paluxy Formation.
- Number to be completed: Five total in-zone monitoring wells for the Longleaf CCS Hub. Located near the edges of expected plume migration in order to monitor the pressure front and track plume location and containment.

Above-Zone Monitoring Wells

- Monitoring Objectives: Monitor pressure, geochemistry, geophysical environment, and detect any leakage.
- Stratigraphic location: The Upper Tuscaloosa Formation. The first porous and permeable zone above the Tuscaloosa Marine Shale, the primary confining zone. Approximate depth of 7,200 ft SS.
- Number to be completed: Two total above-zone monitoring wells for the Longleaf CCS Hub. Located in areas where the increase in Paluxy formation pressure is expected to be the greatest.

Deep USDW Monitoring Wells

- Monitoring Objectives: Monitor geochemistry and detect any leakage.
- Stratigraphic location: The deepest USDW. The Chickasawhay Formation. Approximate depth of 1,700 ft SS.
- Number to be completed: Four total deep USDW monitoring wells for the Longleaf CCS Hub.

Shallow USDW Monitoring Wells

- Monitoring Objectives: Monitor geochemistry and detect any leakage.
- Stratigraphic location: Near-surface freshwater source.
- Number to be completed: Ten total shallow USDW monitoring wells for the Longleaf CCS. Located on existing well pads.

Monitoring data will be collected and used to ensure non-endangerment of USDWs and to confirm nominal injection operations. Additionally, this data will be used to validate and update rigorous numerical modeling performed during the planning and characterization phases of the project. The geologic model and reservoir simulation, being the primary method of forecasting the position, pressure, and saturation of the injected CO_2 within the project area, will ultimately support and demonstrate the safe and permanent storage of CO_2 throughout the project.

This Testing and Monitoring Plan will begin with field-wide monitoring protocols such as CO_2 stream analysis and corrosion monitoring. Then, the Plan will discuss the testing and monitoring activities at each of the five types of project wells, such as continuous monitoring, mechanical integrity testing, pressure falloff testing, plume and pressure front tracking, and groundwater and geochemistry monitoring. The Plan will also discuss further monitoring considerations such as seismicity and fault monitoring. Finally, the Plan will describe the proposed updating and reporting protocols.

B. Carbon Dioxide Stream Analysis

Longleaf CCS, LLC will analyze the CO_2 stream during the injection period to collect representative chemical and physical characteristic data, following the requirements of 40 CFR 146.90(a). Longleaf CCS, LLC expects multiple sources of CO_2 from the Mobile, AL region, with additional sources to be added throughout the life of the project. Each source will have a somewhat different gas stream composition based on the source's capture process, and the composition of the final injected gas stream will change depending on which sources are operational and not undergoing maintenance. As such, the CO_2 stream will be sampled continuously and represent the final gas, combined from all sources, that is injected. It is expected that the final CO_2 stream will have a mol% CO_2 concentration of at least 96%.

B.1. CO_2 Stream Sampling Location and Frequency

Longleaf CCS, LLC will analyze the CO_2 stream during the injection period to collect representative chemical and physical characteristic data. Baseline parameters will be established at the start of injection and occur continuously throughout the injection period using an on-site gas chromatograph. Longleaf CCS, LLC will report the results of the CO_2 stream analysis in semi-annual operational reports (see subsection *K.1. Semi-Annual Reporting* below).

In the event of unplanned disruptions to permitted injection activities that may affect the chemical and physical characteristics of the final CO_2 stream, Longleaf CCS, LLC will increase the frequency of CO_2 stream reporting to the UIC Program Director to confirm there are no significant changes and injection is continuing to operate as permitted.

B.2. CO_2 Stream Analytical Parameters

The CO_2 stream samples will be analyzed for the constituents shown in **Table 1** using a gas chromatograph. The list of parameters will be altered if analysis from the CO_2 stream demonstrates additional constituents to be considered. Amendments to this Plan must be approved by the UIC Program Director (see Section *J. Updating the Testing and Monitoring Plan* below).

B.3. CO_2 Stream Sampling Methods

CO_2 stream sampling will occur at the master meter located on the Injection Well LL#2 wellsite, the custody transfer point of the injection field. A gas chromatograph will be installed to analyze the CO_2 stream every 30 minutes to ensure the quality of the CO_2 stream. Physical samples will be sent quarterly to be analyzed for Hydrogen Sulfide and total Sulfur. Additional details regarding the specific procedures for CO_2 stream sample collection and precision are described in the *Quality Assurance and Surveillance Plan (QASP)*, which is attached to this Plan as an appendix.

Table 1: Summary of Anticipated CO_2 Stream Composition.

Component	Specification	Unit
Minimum CO_2	>96	mole%, dry basis
Water content	<20	lb/MMscf
Impurities (dry basis):		
Total Hydrocarbons	<2	mol%
Inert Gases (N_2, Ar, O_2)	<4	mol%
Hydrogen	<1	mol%
Alcohols, aldehydes, esters	<500	ppmv
Hydrogen Sulfide	<100	ppmv
Total Sulfur	<100	ppmv
Oxygen	<100	ppmv
Carbon monoxide	<100	ppmv
Glycol	<1	ppmv

B.4. Laboratory and Chain of Custody Procedures

All physical CO_2 stream samples collected quarterly will be analyzed by a third-party laboratory using standardized procedures for gas chromatography, mass spectrometry, detector tubes, and photo ionization. All sample containers will be labeled with a unique sample identification number and sampling date. Samples will be logged into a database with any notes. The sample chain of custody procedure is described in the *QASP.*

C. Corrosion Monitoring

Longleaf CCS, LLC will monitor for the corrosion of well materials that will be in contact with the CO_2 stream in order to confirm safe injection and storage of CO_2 and meet the requirements of 40 CFR 146.90(c). Well materials will be monitored for any evidence of cracking, pitting, or other signs of corrosion to ensure that components meet the minimum standards for material strength and performance.

C.1. Design and Materials

Coupons consisting of material that will directly contact the CO_2 stream will be placed within a flowline. Each sample will be attached to an individual holder and inserted in a flowthrough pipe arrangement, exposing the samples to the CO_2 stream and allowing access for removal and testing. The flowthrough pipe arrangement will be located downstream of all process compression, dehydration, and pumping equipment (i.e., at the beginning of the flowline to the well piping). A parallel stream of high-pressure CO_2 will be routed from the flowline through the corrosion monitoring system. This loop will operate while injection is occurring, providing representative exposure of the samples to the CO_2 composition, temperature, and pressures that will be seen at the wellhead and injection tubing. Injection will be able to continue while samples are removed for testing.

Coupon samples of the materials used to construct the CO_2 flowlines/pipelines, long string casing, injection tubing, wellhead, and packers will be monitored for corrosion. The construction materials for these pieces of equipment are listed below in **Table 2** and are consistent with the materials listed in Section *4.1 Well Design* of the *Application Narrative*.

Table 2: List of Equipment Coupon with Material of Construction.

Equipment Coupon	Material of Construction
Pipeline	API 5L X42 PSL2, API 5L X52 PSL2 API 5L X60, API 5L X65 PSL2 API 5L or X70 PSL2 carbon steel
Long String Casing (Depths 8,000 ft – 11,400 ft)	13% Chromium Stainless Steel
Injection Tubing	13% Chromium Stainless Steel
Wellhead	13% Chromium Stainless Steel
Packers	13% Chromium Stainless Steel

C.2. Methodology, Frequency, and Handling

Corrosion monitoring coupons will be weighed, measured, and photographed prior to initial exposure. Then, coupons will be removed quarterly and assessed for corrosion using the NACE RP0775-2018[2] standard or a similarly accepted standard practice for preparing, cleaning, and evaluating corrosion test specimens. Upon removal, coupons will be photographed and inspected visually with a minimum of 10x power for evidence of

[2] The National Association of Corrosion Engineers (NACE) Standard RP0775, (2018). *Preparation, Installation, Analysis, And Interpretation of Corrosion Coupons In Oilfield Operations*, Houston, TX. ISBN 1-57590-086-6.

corrosion such as cracking or pitting. The weight and size (thickness, width, and length) of the coupons will be measured and recorded to within 0.0001 gm and 0.0001 inch. The corrosion rate will be calculated as the weight loss during the exposure period divided by the duration of exposure (i.e., weight loss method).

Longleaf CCS, LLC will also employ additional monitoring techniques to ensure USDW protection and guard against corrosion. These techniques include cased hole pulsed neutron capture (PNC) logs, flow profile surveys, ultrasonic cement bond logs as necessary, mechanical integrity testing (MIT), and annular pressure monitoring. The location and frequency of these techniques are described in *Section D. Injection Well Monitoring, Section E. In-Zone Observation Well Monitoring, and Section F. Above-Zone Observation Well Monitoring.*

Casing and tubing will be evaluated for corrosion as necessary by running wireline casing inspection logs. Furthermore, wireline tools can be lowered into the well to directly measure properties of the well tubulars that indicate corrosion. These tools, which may be used to monitor and assess the condition of well tubing and casing, include:

- Mechanical casing evaluation tools, referred to as calipers, have multiple articulated arms attached to the tool that measure the inner diameter of the tubular as the caliper is raised or lowered through the well.
- Ultrasonic tools, which are capable of measuring wall thickness in addition to the inner diameter of the well tubular and can also provide information about the outer surface of the casing or tubing.
- Electromagnetic tools, which are capable of distinguishing between internal and external corrosion effects using variances in the magnetic flux of the tubular being investigated. These tools are able to provide circumferential images with high resolution such that pitting depths, due to corrosion, can often be accurately measured.

D. Injection Well Monitoring

D.1. Summary of Injection Well Monitoring Activities

Injection wells at the Longleaf CCS Hub will be completed in the Paluxy Formation at an approximate depth of 10,100 ft MSL. All four injection wells will provide key pressure data, plume tracking, and geophysical monitoring data that will confirm the safe injection and storage of CO_2 without endangerment to USDWs. Testing and monitoring activities will include the continuous monitoring of injection parameters, mechanical integrity testing, pressure transient testing, and plume and pressure front tracking. **Table 3** below displays the testing and monitoring activities that will be deployed at the four Longleaf CCS Hub injection wells. **Figure 1** shows the location of Injection Wells LL#1, LL#2, LL#3, and LL#4 the Longleaf CCS Hub.

Table 3: Summary of Testing and Monitoring Activities to be Conducted at the Injection Wells.

Monitoring Activity/Test		Purpose	Baseline Frequency	Injection Period Frequency	Post-Injection Site Care Frequency
Fiber Optic / Seismic Monitoring	Distributed Acoustic Sensing (DAS)	Indirect geophysical monitoring	Beginning before injection	Continuous	Continuous
	Distributed Temperature Sensing (DTS)	Well integrity/leak detection	Beginning before injection	Continuous	Continuous
Pulsed Neutron Capture Log (PNC)		Geophysical monitoring	Once before injection	3yrs after injection begins; Every 5yrs after	At end of injection; Every 5yrs after
Mechanical Integrity Tests		Well integrity/leak detection	Once before injection	Annually	Annually
Pressure Transient Test		Geophysical monitoring	Once before injection	3yrs after injection begins; Every 5yrs after	At end of injection; Every 5yrs after
Flow Profile Survey		Injection process monitoring	N/A	Every 5yrs	N/A
Bottomhole Pressure Monitoring		Pressure monitoring	Beginning before injection	Continuous surface read-out	Continuous surface read-out
Wellhead Pressure Monitoring	Tubing	Pressure monitoring/ leak detection	Beginning before injection	Continuous	Continuous
	Annulus	Pressure monitoring/ leak detection	Beginning before injection	Continuous	Continuous
Injection Rate and Volume Monitoring		Injection process monitoring	N/A	Continuous	N/A

D.2. Injection Well Continuous Monitoring

Pursuant to 40 CFR 146.90(b), Longleaf CCS, LLC will install and use continuous recording devices to monitor the injection pressure, rate, and volume; the pressure of the annulus between the tubing and the long string casing; the annulus fluid volume added;

and the temperature of the CO_2 stream. All monitoring will be continuous for the duration of the injection period. Parameters, device, location, and sampling frequency are outlined in **Table 4** below.

Above-ground pressure and temperature instruments shall be calibrated over the full operational range annually, using American National Standards Institute (ANSI) or other industry recognized standards. Pressure transducers shall have a drift stability of less than 3 psi over the operational period of the instrument and an accuracy of ± 5 psi. Sampling rates will be at least once every 5 seconds. Temperature sensors will be accurate to within one degree Celsius. Downhole and surface pressure and temperature gauge specifications are described in more detail in the *QASP.*

Injection rate (flow) will be monitored with a Coriolis mass flowmeter at the wellhead. The flowmeter will be calibrated for the entire expected range of flow rates using generally accepted standards and accurate to within ± 1.0 percent.

D.2.1. Injection Rate and Pressure Monitoring

Longleaf CCS, LLC will monitor injection operations using a distributive process control system (DPCS). The Surface Facility Equipment & Control System will limit maximum instantaneous flow to 4,110 mt/d and/or limit the well head pressure to 2,000 psia, which corresponds to well below the regulatory requirement to not exceed 90% of the injection zone's fracture pressure. Maximum annual injection will not exceed 1.25 Mt/y or an average of 3,425 mt/d. All critical system parameters (e.g., pressure, temperature, and flow rate) will have continuous electronic monitoring with signals transmitted back to a master control system. The system will sound an alarm and shutdown operations should specified control parameters exceed their normal operating range at any time. Longleaf CCS, LLC supervisors and operations personnel will have the capability to monitor the status of the system comprehensively from distributive control centers.

Table 4: Sampling Devices, Locations, and Frequencies for Continuous Monitoring at Injection Wells.

Parameter	Device(s)	Location	Min. Sampling Frequency (active / shut-in)	Min. Recording Frequency (active / shut-in)
Injection Pressure Monitoring	Bottomhole surface read-out pressure gauge	Downhole	5 sec. / 4 hours	5 mins. / 4 hours
Injection Rate Monitoring	Coriolis flow meter and flow computer	Surface	5 sec. / 4 hours	5 mins. / 4 hours
Injection Volume Monitoring	Coriolis flow meter	Surface	5 sec. / 4 hours	5 mins. / 4 hours
Casing Pressure Monitoring	Continuous annular pressure gauge, annulus fluid reservoir, pressure regulators, tank fluid indication	Surface	5 sec. / 4 hours	5 mins. / 4 hours
Tubing Pressure Monitoring	Continuous surface pressure gauge	Surface	5 sec. / 4 hours	5 mins. / 4 hours
Annulus Fluid Volume Monitoring	Continuous surface pressure gauge	Surface	5 sec. / 4 hours	5 mins. / 4 hours
CO_2 Stream Temperature Monitoring	Surface temperature gauge	Surface	5 sec. / 4 hours	5 mins. / 4 hours
Distributed Acoustic Sensing (DAS)	Fiber optic cable	Downhole	<1 sec. / <1 sec.	<5 min / <10 min
Distributed Temperature Sensing (DTS)	Fiber optic cable	Downhole	10 min / 10 min	10 min / 10 min

Notes:

- Sampling frequency refers to how often the monitoring device obtains data from the well for a particular parameter. For example, a recording device might sample a pressure transducer monitoring injection pressure once every two seconds and save this value in memory.
- Recording frequency refers to how often the sampled information is recorded to digital format (such as a computer hard drive). For example, the data from the injection pressure transducer might be recorded to a hard drive once every minute.

D.2.2. Injection Well Annulus Pressure Monitoring

Longleaf CCS, LLC will use the procedures below to monitor annular pressure. The following procedures will be used to minimize the potential for any unpermitted fluid movement into or out of the annulus:

- The annulus between the tubing and the long string of casing will be filled with brine and a corrosion inhibitor (*3.1 Operational Conditions* in the *Injection Well Operations Plan)*.
- The surface annulus pressure will be kept within a range of 375 psia ± 125 psia.
- At all times during injection, the bottomhole tubing – long-string casing annulus pressure will be maintained at a pressure higher than the bottomhole injection pressure of the injection interval.

Figure 3 below shows the process instrument diagram for the injection well annulus protection system. The annular monitoring system consists of a continuous annular pressure gauge, a pressurized annulus fluid reservoir (annulus head tank), pressure regulators, and tank fluid level indicator. The annulus system will maintain annulus pressure by controlling the pressure on the annulus head tank using either compressed nitrogen, CO_2, or pressure pump.

The annular pressure between the tubing and the long-string casing will be maintained at a higher pressure than the injection pressure, at bottomhole conditions, during injection and will be monitored by the Longleaf CCS, LLC control system gauges. The annulus head tank pressure will be controlled by pressure regulators or pumps; one set of regulators or pumps will be used to maintain pressure above injection pressure if needed by adding compressed nitrogen or CO_2 and the other to relieve pressure if needed by venting gas or fluid from the annulus head tank. Any changes to the composition of annular fluid will be submitted to the UIC Program Director for approval.

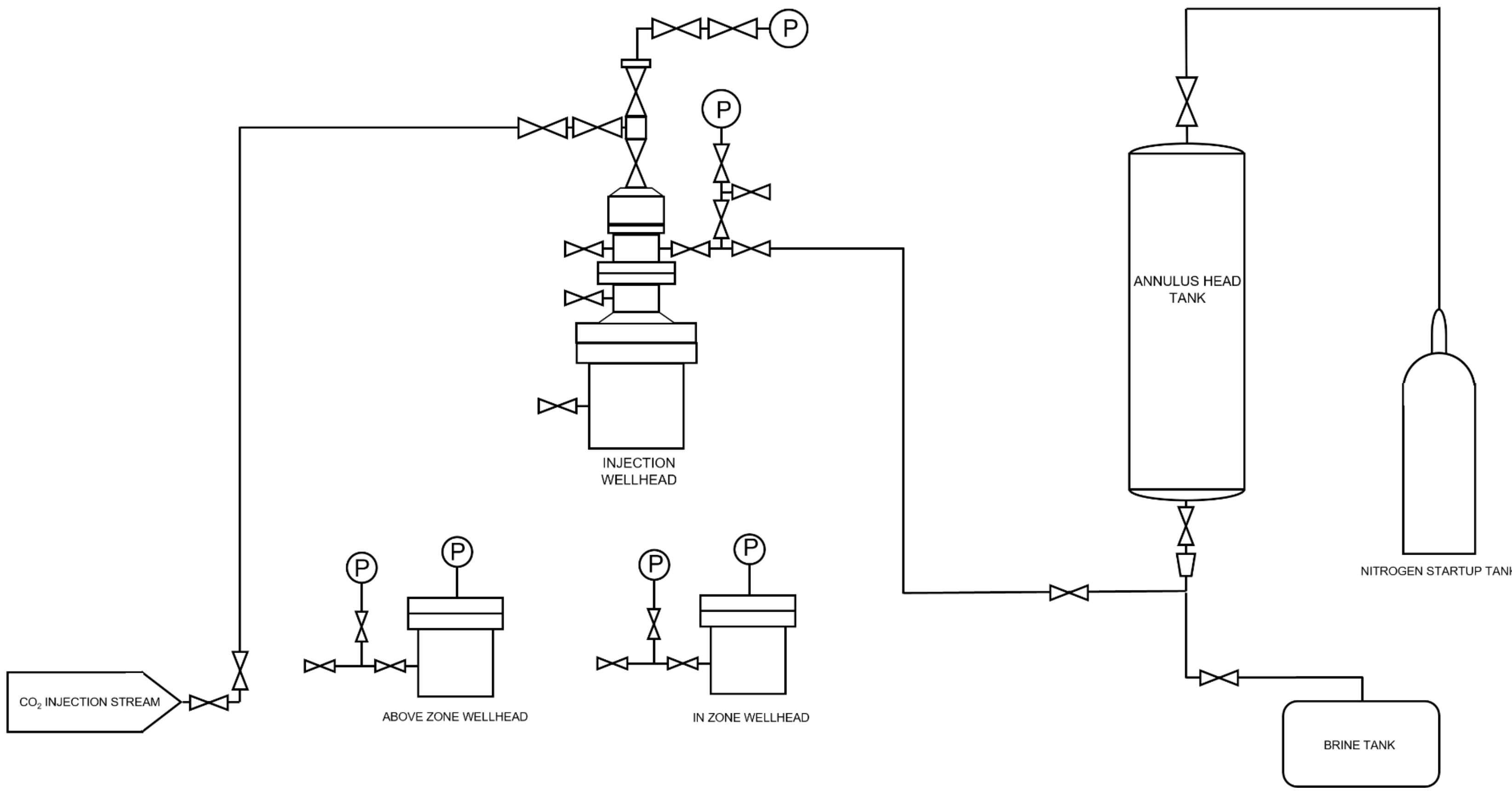

Figure 3: Annular Monitoring System General Layout

If system communication were to be lost for greater than 60 minutes, project personnel will observe and monitor manual gauges in the field every eight hours or once per shift for both wellhead surface pressure and annulus pressure, while also recording hard copies of the data until communication is restored.

Average annular pressure, annulus tank fluid level, and volume of fluid added or removed from the system will be recorded daily and reported as monthly averages in the semi-annual report (see subsection *K.1 Semi-Annual Reporting*).

As detailed in the *Emergency and Remedial Response Plan (ERRP)*, significant changes in the casing-tubing annular pressure attributed to well mechanical integrity will be investigated.

D.2.3. Fiber Optic Cable Deployment

Longleaf CCS, LLC will deploy fiber optic cable on the outside of the long string casing for all injection wells, equipped through the Tuscaloosa Marine Shale. Fiber optic cable will enable continuous micro-seismic and geophysical monitoring through distributed acoustic sensing (DAS) and well integrity assurance and leak detection through distributed temperature sensing (DTS).

D.3. Injection Well Mechanical Integrity Testing

Longleaf CCS, LLC will conduct at least one of the tests presented below in **Table 5** periodically during the injection phase to verify external mechanical integrity as required by 40 CFR 146.90(e). Demonstrating and maintaining the mechanical integrity of the injection well is key to protecting USDWs because the well is a possible conduit for fluid movement through the confining interval.

The condition of the cement and casing will be verified using downhole logging techniques and tools to determine there is no fluid flow behind the casing or channels in the cement. An ultrasonic cement bond inspection log and an electromagnetic casing inspection log will be run through the entire length of the long-string casing before injection begins. During injection, the absence of any leaks in the casing, injection tubing, and packer will be demonstrated using annulus pressure tests conducted annually.

Table 5. Showing MIT Description and Frequency at Injection Wells.

Test Description	Frequency During Injection Period
Pressure Falloff Testing	Minimum of once per 5 years, during planned well maintenance
Annulus Pressure Test	Annually
Annulus Pressure Monitoring	Continuous
Pulsed Neutron Capture (PNC) Log	Baseline before injection; 3yrs after injection begins; Every 5yrs thereafter
Distributed Temperature Sensing (DTS)	Continuous
Temperature Logging	Baseline before injection; 3yrs after injection begins; Every 5yrs thereafter
Ultrasonic Cement Bond Inspection Log	Once before injection
Electromagnetic Casing Inspection Log	Once before injection

PNC logs will be run at least once prior to the start of CO_2 injection, 3 years after injection begins, and every five years thereafter until the well is plugged and abandoned. PNC logs can identify potential fugitive CO_2 movement by quantifying the fluid saturations around the wellbore and the presence of CO_2[3]. Following a baseline, subsequent logs can be compared to determine changes in fluid flow and saturation adjacent to the wellbore and detect any formation of channels or other fluid isolation concerns related to the well. A temperature log will be deployed in conjunction with PNC logging to further evaluate mechanical integrity.

Continuous DTS monitoring will provide additional comprehensive mechanical integrity confirmation by continuously monitoring for areas along the wellbore with anomalous changes in temperature.

[3] Conner, A., Place, M., Chace, D., and Gupta, N., September 2020, "Pulsed Neutron Capture for Monitoring CO_2 Storage with Enhanced Oil Recovery in Northern Michigan", Battelle, Volume II.F, Midwestern Regional Carbon Sequestration Partnership (MRCSP) Phase III, Submitted to The U.S. Department of Energy, National Energy Technology Laboratory, DOE MRCSP Project #DE-FC26-05NT42589, https://www.osti.gov/servlets/purl/1773351.

Notice of intent to conduct routine pressure tests, temperature logs, and any additional mechanical tests, logs, or inspections will be provided to the UIC Program Director at least 30 days prior to the demonstration of mechanical integrity. In the case of unscheduled or remedial well activity, the UIC Program Director will receive a remediation plan that includes a MIT activity to demonstrate well integrity following the intervention (see *ERRP*). The results of any injection well test or MIT will be provided to the UIC Program director within 30 days after the test.

D.4. Injection Well Pressure Transient Testing

Pursuant to 40 CFR 146.90(f), Longleaf CCS, LLC will perform pressure falloff tests during the injection phase to confirm site characterization information, inform AoR reevaluation, and verify that the project is operating properly and the injection zone is responding as predicted. Tests will occur once before injection (baseline), after 3 years from the start of injection, and every 5 years thereafter until well abandonment.

A pressure falloff test includes a period of injection followed by a period of non-injection or shut down. Normal injection using the CO_2 stream provided by the Longleaf CCS Hub will be used during the injection period preceding the shut-in portion of the falloff tests. Injection rates on a well-by-well basis are continuously recorded and will be employed in the analysis of the continuously recorded subsurface pressure data. The Operator will strive to have a minimum of one week of relatively continuous injection to precede the shut-in portion of the falloff test. This data will be measured using a surface readout downhole gauge.

Because surface readout will be used and downhole recording memory restrictions will be eliminated, data will be collected at intervals of five seconds or less for the duration of test. The shut-in period of the falloff test will be a minimum of four days, continuing until adequate pressure transient data are collected to calculate the average pressure. A report containing the pressure falloff data and interpretation of the reservoir ambient pressure will be submitted to the UIC Program Director within 90 days of the test. Pressure sensors used for this test will be the wellhead sensors and a downhole gauge for the pressure falloff test. Each gauge will be of a type that meets or exceeds ASME B 40.1[4] Class 2A (0.5% accuracy across full range of pressures). Wellhead and downhole gauge specifications are described in detail in the *QASP.*

D.5. Injection Well Plume and Pressure Front Tracking

Longleaf CCS, LLC will utilize direct and indirect methods to track the extent of the CO_2 plume and the presence or absence of elevated pressure to meet the requirements of 40 CFR 146.90(g).

Direct monitoring of pressure will be used to assess the lateral extent of injected CO_2 and the pressure front within the injection zone. In addition to surface methods, downhole geophysical methods and logging tools will be used to provide an indirect measure of CO_2 plume development and spatial distribution. This section describes the proposed injection zone monitoring program.

During the active injection phase, continuous (i.e., uninterrupted) downhole monitoring of pressure will be conducted in the four CO_2 injection wells. The pressure gauges will be removed from the wells only when they require maintenance or when necessitated by other activities (e.g., well maintenance). Formation fluid sampling will not occur in the four CO_2 injection wells during the operational phase so as not to interfere with injection operations.

The primary objective of monitoring injection zone pressure is to provide data needed to adequately assess the lateral extent of injected CO_2 and the pressure front over time. Specific objectives for monitoring injection zone pressure include the following:

- Calibrate the numerical models that will be used to help track CO_2 and pressure in the injection zone.
- Guard against over-pressuring, which could induce unwanted fracturing of the injection zone or the overlying confining zone(s).

[4] The American Society of Mechanical Engineers (ASME), B40.100 – 2022, “Pressure Gauges and Gauge Attachments”, Published 2022, ISBN 9780791875285.

- Determine the need for well rehabilitation.
- Assess injection zone properties (e.g., permeability, porosity, reservoir size) within progressively larger areas of the reservoir as the pressure front advances.

D.5.1. Plume Monitoring

Longleaf CCS, LLC will collect baseline, pressurized fluid samples from the injection interval (Paluxy Formation) at each of the four injection wells in accordance with 40 CFR 146.87(b)-(c). More information on the parameters to be analyzed as part of fluid sampling in the injection zone as well as the results from injection zone fluid sampling are provided in the ***Pre-Operational Testing Plan***. Longleaf CCS, LLC will not collect fluid samples from the injection wells during the injection period to avoid interrupting normal injection operation.

Indirect plume monitoring will be conducted using PNC logs and vertical seismic profiles (VSPs) to monitor CO_2 saturations and to track the movement of the expected CO_2 plume. Longleaf CCS, LLC will conduct PNC logging and VSPs once before injection, 3 years after injection begins, and every 5 years thereafter during the injection period, as well as before the plugging and abandonment of any injection well.

Longleaf CCS, LLC will also employ a temperature log that will be deployed and collected in conjunction with each PNC logging run. The information from these logging activities will provide ample data sets to calibrate the geologic models incorporated within the numerical models to the field performance data.

D.5.2. Pressure-front Monitoring

Injection of CO_2 into a saline aquifer generates pressure perturbations that diffuse through the fluid-filled pores of the geologic system. The objective of pressure monitoring is to record the pressure signal at the source (i.e., injection well) and one or more monitoring wells to infer important rock and fluid characteristics such as permeability and total compressibility from the analysis of the pressure data. Pressure monitoring information also provides input for the calibration of numerical models, where injection zone properties are adjusted to match the observed pressure data with corresponding simulation predictions. This provides confirmation of predictions regarding the extent of the CO_2 plume, pressure buildup, and the occurrence of fluid displacement into overlying formations.

Pressure in the injection zone will be monitored continuously with a downhole surface read-out gauge at all four injection wells. Pressure monitoring as a component of the overall MVA program provides multiple benefits. Inferences about formation permeability at scales comparable to that of CO_2 plume migration can be made (as opposed to that from small centimeter-scale core samples). Permeability values estimated for different regions of the injection zone may indicate the presence of anisotropy and, hence, suggest potential asymmetry in the plume trajectory. Such information can be useful in adapting the monitoring strategy.

Pressure monitoring in the injection well will be performed using a real-time monitoring system with surface read-out capabilities so that pressure gauges do not have to be removed from the well to retrieve data. The following measures will be taken to ensure that the pressure gauges are providing accurate information on an ongoing basis:

- High-quality (high-accuracy, high-resolution) gauges with low drift characteristics will be used.
- Gauge components (gauge, cable head, cable) will be manufactured of materials designed to provide a long-life expectancy for the anticipated downhole conditions.
- Upon acquisition, a calibration certificate will be obtained for every pressure gauge. The calibration certificate will provide the manufacturer’s specifications for range, accuracy (% full scale), resolution (% full scale), drift (< psi per year) and calibration results for each parameter. The calibration certificate will also provide the date that the gauge was calibrated, and the methods and standards used.
- Gauges will be installed above the completion packer in the long-string casing-tubing annulus so they can be removed if necessary for recalibration by removing the tubing string. Redundant gauges may be run on the same cable to provide confirmation of downhole pressure and temperature.

- Upon installation, all gauges will be tested to verify they are functioning (reading/transmitting) correctly.

- Gauges will be pulled and recalibrated each time a workover occurs that involves removal of tubing. A new calibration certificate will be obtained each time a gauge is re-calibrated.

Longleaf CCS, LLC will conduct injection flow profile surveys every five years at each of the four injection wells to understand how the injection stream is partitioned across the perforations. This will provide ample data sets to calibrate the geologic models incorporated within the numerical models to the field performance data.

E. In-Zone Observation Well Monitoring

E.1. Summary of In-Zone Monitoring Activities

In-zone monitoring wells at the Longleaf CCS Hub will be completed in the Paluxy Formation at an approximate depth of 10,100 ft SS. Five in-zone monitoring wells will provide key data on pressure, plume tracking, and geophysical monitoring that will confirm the safe injection and storage of CO_2 without endangerment to USDWs. Testing and monitoring activities will include continuous pressure monitoring, mechanical integrity testing, pressure transient testing, and plume and pressure front tracking. **Table 6** below displays all of the testing and monitoring activities that will be deployed at each of the five in-zone monitoring wells.

E.2. Placement of In-Zone Observation Wells

The primary objective of the five in-zone monitoring wells at the Longleaf CCS Hub is to directly monitor the movement and development of the CO_2 plume and pressure front. The spatial distribution of in-zone monitoring wells, shown in **Figure 1**, will allow Longleaf CCS, LLC to track and confirm the CO_2 plume over the course of the 30-year injection period.

Table 6: Summary of Testing and Monitoring Activities at In-Zone Monitoring Wells.

Monitoring Activity/Test		Purpose	Baseline Frequency	Injection Period Frequency	Post-Injection Site Care Frequency
Fiber Optic / Seismic Monitoring	Distributed Acoustic Sensing (DAS)	Indirect geophysical monitoring	Beginning before injection	Continuous	Continuous
	Distributed Temperature Sensing (DTS	Well integrity/leak detection	Beginning before injection	Continuous	Continuous
Pulsed Neutron Capture Log (PNC)		Geophysical monitoring	Once before injection	3yrs after injection begins; Every 5yrs after	At end of injection; Every 5yrs after
Mechanical Integrity Tests		Well integrity/leak detection	Once before injection	Annually	Annually
Bottomhole Pressure Monitoring		Pressure monitoring	Beginning before injection	Continuous surface read-out	Continuous surface read-out
Wellhead Tubing and Annulus Pressure Monitoring		Pressure monitoring/leak detection	Beginning before injection	Continuous	Continuous

Longleaf CCS, LLC chose the locations for the in-zone monitoring wells based on the expected pressure front and the CO_2 plume development as determined through a rigorous modeling approach, the details of which are provided in section *A.3.d Executing the Computational Model Section* of the *Area of Review and Corrective Action Plan*. Near-field in-zone monitoring wells allow the development of the pressure front and CO_2 plume to be monitored while far-field in-zone monitoring wells ensure lateral containment. These in-zone monitoring wells provide Longleaf CCS, LLC with pressure data to validate the geologic and computational models to confirm that the CO_2 plume is behaving in an expected and predictable manner.

E.3. In-Zone Observation Well Continuous Monitoring

Longleaf CCS, LLC will install and use continuous recording devices to monitor the formation pressure and the pressure of the annulus between the tubing and the long string casing. All monitoring will be continuous for the duration of the injection period. Parameters, device, location, and sampling frequency are outlined in **Table 7** below.

Table 7: Sampling Devices, Locations, and Frequencies for Continuous Monitoring at In-Zone Monitoring Wells.

Parameter	Device(s)	Location	Min. Sampling Frequency (active / shut-in)	Min. Recording Frequency (active / shut-in)
Injection Interval Pressure Monitoring	Bottomhole surface read-out pressure gauge	Downhole	5 sec. / 4 hours	5 mins. / 4 hours
Casing Pressure Monitoring	Continuous annular pressure gauge	Surface	5 sec. / 4 hours	5 mins. / 4 hours
Tubing Pressure Monitoring	Continuous surface pressure gauge	Surface	5 sec. / 4 hours	5 mins. / 4 hours
Distributed Acoustic Sensing (DAS)	Fiber optic cable	Downhole	<1 sec. / <1 sec.	<5 min / <10 min
Distributed Temperature Sensing (DTS)	Fiber optic cable	Downhole	10 min / 10 min	10 min / 10 min

Notes:

- Sampling frequency refers to how often the monitoring device obtains data from the well for a particular parameter. For example, a recording device might sample a pressure transducer monitoring injection pressure once every two seconds and save this value in memory.
- Recording frequency refers to how often the sampled information is recorded to digital format (such as a computer hard drive). For example, the data from the injection pressure transducer might be recorded to a hard drive once every minute.

Above-ground pressure instruments shall be calibrated over the full operational range at least annually using ANSI or other industry recognized standards. Pressure transducers shall have a drift stability of less than 3 psi over the operational period of the instrument and an accuracy of ± 5 psi. Sampling rates will be at least once every 5 seconds.

Longleaf CCS, LLC will deploy fiber optic cable on the outside of the long string casing for all in-zone monitoring wells through the Tuscaloosa Marine Shale. Fiber optic cable will enable continuous micro-seismic and geophysical monitoring through DAS and well integrity assurance and leak detection through DTS.

E.4. In-Zone Observation Well Mechanical Integrity Testing

Longleaf CCS, LLC will conduct at least one of the tests presented below in **Table 8** periodically during the injection phase to verify external mechanical integrity in all in-zone monitoring wells. Demonstrating and maintaining the mechanical integrity of the in-zone monitoring wells is key to protecting USDWs because these wells are a possible conduit for fluid movement through the confining interval and will also satisfy the State Oil and Gas Board of Alabama regulatory guidelines for monitoring wells.

Table 8. Showing MIT Test Description and Frequency at In-Zone Monitoring Wells.

Test Description	Frequency During Injection Phase
Annulus Pressure Test	Annually
Annulus Pressure Monitoring	Continuous
Pulsed Neutron Capture (PNC) Log	Baseline before injection; 3yrs after injection begins; Every 5yrs thereafter
Distributed Temperature Sensing (DTS)	Continuous
Temperature Logging	Baseline before injection; 3yrs after injection begins; Every 5yrs thereafter
Ultrasonic Cement Bond Inspection Log	Once before injection

The condition of the cement and casing will be verified using downhole logging techniques and tools to determine there is no fluid flow behind the casing or channels in the cement. An ultrasonic cement bond inspection log and electromagnetic casing inspection log will be run through the entire length of the long-string casing during well construction.

PNC logs will be run at least once prior to the start of CO_2 injection, 3 years after injection begins, and every five years thereafter until the well is plugged and abandoned. PNC logs can identify potential fugitive CO_2 movement by quantifying the flow of water around the wellbore and the presence of CO_2. Following a baseline, subsequent logs can be compared to determine changes in fluid flow and saturation adjacent to the wellbore and detect any formation of channels or other fluid isolation concerns related to the well. A temperature log will be deployed in conjunction with PNC logging to further evaluate mechanical integrity.

Continuous DTS monitoring will provide additional comprehensive mechanical integrity confirmation by continuously monitoring for areas along the wellbore with anomalous changes in temperature. The annulus between the tubing and the long string of casing will be filled with brine and a corrosion inhibitor and a pressure gauge will continuously monitor the annular pressure.

E.5. In-Zone Plume and Pressure Front Tracking

Longleaf CCS, LLC will utilize direct and indirect methods to track the extent of the CO_2 plume and the presence or absence of elevated pressure during the operation period to meet the requirements of 40 CFR 146.90(g).

Direct monitoring of pressure will be used to assess the lateral extent of injected CO_2 and the pressure front within the injection zone. In addition to surface methods, downhole geophysical methods and logging tools will be used to provide an indirect measure of CO_2 plume development and spatial distribution. This section describes the proposed injection zone monitoring program for the five in-zone monitoring wells.

E.5.1. Plume Monitoring

As discussed in subsection *E.2* above, the locations of the five in-zone monitoring wells will enable Longleaf CCS, LLC to directly monitor the movement and progression of the CO_2 plume. The spatial distribution of the monitoring well network will allow Longleaf CCS, LLC to validate and update its reservoir model with real pressure and saturation data and confirm that the CO_2 plume is behaving as expected.

Indirect plume monitoring will be conducted using PNC logs and VSPs to monitor CO_2 saturations and to track the movement of the expected CO_2 plume. Longleaf CCS, LLC will conduct PNC logging and VSPs once before injection, 3 years after injection begins, and every 5 years thereafter during the injection phase, as well as before the plugging and abandonment of any injection well.

Longleaf CCS, LLC will also employ a temperature log that will be deployed and collected in conjunction with each PNC logging run. The information from these logging activities will provide data to calibrate the geologic and computational models to the field performance data.

E.5.2. Pressure-front monitoring details

Pressure monitoring at the five in-zone monitoring wells will be performed using a real-time monitoring system with surface read-out capabilities so that pressure gauges do not have to be removed from the well to retrieve data. The measurements listed in section *D.5.2 Injection Wells Pressure Monitoring* will be taken to ensure that the pressure gauges provide accurate information on an ongoing basis.

The pressure data collected will be used to track the pressure front over the operational period and provide valuable feedback to the computational reservoir model. An abundance of pressure data from the injection interval will aid Longleaf CCS, LLC during AoR reevaluations to ensure the most accurate geologic and reservoir model is being used.

F. Above-Zone Observation Well Monitoring

F.1. Summary of Above-Zone Well Monitoring Activities

Deep USDW monitoring wells at the Longleaf CCS Hub will be completed in the first porous and permeable interval above the confining unit, the Tuscaloosa Marine Shale in the Upper Tuscaloosa Formation at an approximate depth of 7,200 ft SS. Two above-zone monitoring wells will be completed to monitor pressure, geochemistry, and the geophysical environment and to detect any CO_2 leakage. Testing and monitoring activities will include the continuous monitoring of pressures, mechanical integrity testing, pressure transient testing, geophysical monitoring/plume and pressure front tracking, and ground water and geochemistry testing. **Table 9** below displays the testing and monitoring activities that will be deployed at the Longleaf CCS Hub above-zone monitoring wells.

F.2. Placement of Above-Zone Observation Wells

Longleaf CCS, LLC considered geologic site data, the presence of artificial penetrations, community impact, and the results of an extensive reservoir modeling effort to determine the location for above-zone monitoring wells that will best ensure non-endangerment to USDWs and local communities. The placement of the two above-zone monitoring wells is based on an internally conducted risk assessment. **Figure 1** provides the location of the one near-field above-zone monitoring well and the one far-field above-zone monitoring well.

Table 9: Summary of Testing and Monitoring Activities at Above-Zone Monitoring Wells.

Monitoring Activity/Test		Purpose	Baseline Frequency	Injection Period Frequency	Post-Injection Site Care Frequency
Fiber Optic / Seismic Monitoring	Distributed Acoustic Sensing (DAS)	Indirect geophysical monitoring	Beginning before injection	Continuous	Continuous
	Distributed Temperature Sensing (DTS	Well integrity/leak detection	Beginning before injection	Continuous	Continuous
Pulsed Neutron Capture Log (PNC)		Geophysical monitoring	Once before injection	3yrs after injection begins; Every 5yrs after	At end of injection; Every 5yrs after
Mechanical Integrity Tests		Well integrity/leak detection	Once before injection	Every 5yrs	Every 5yrs
Bottomhole Pressure Monitoring		Pressure monitoring	Beginning before injection	Continuous surface read-out	Continuous surface read-out
Wellhead Tubing and Annulus Pressure Monitoring		Pressure monitoring/leak detection	Beginning before injection	Continuous	Continuous

Monitoring Activity/Test	Purpose	Baseline Frequency	Injection Period Frequency	Post-Injection Site Care Frequency
Fluid Sampling	Leak detection/ geochemistry monitoring	At least 3 sampling events prior to injection	Quarterly for first yr; Annually thereafter	Annually

Above-zone monitoring well AOB#1 will be placed in the middle of the four planned injection wells at the Longleaf CCS Hub. The results of reservoir modeling have determined that this is where pressure will increase the greatest in the Paluxy Formation injection interval during the injection period. Above-zone monitoring well AOB#2 will be placed in the far-field towards the western edge of the AoR to provide information as the CO_2 plume migrates up-structure.

Existing well penetrations are not expected to be a risk for CO_2 leakage at the Longleaf CCS Hub. There are no existing wells that penetrate the Tuscaloosa Marine Shale within the AoR.

F.3. Above-Zone Observation Well Continuous Monitoring

Longleaf CCS, LLC will install and use continuous recording devices to monitor the above-zone formation pressure and the pressure of the tubing at the wellhead, and the pressure of the annulus between the tubing and the long string casing. All monitoring will be continuous for the duration of the injection period. Parameters, device, location, and sampling frequency are outlined in **Table 10** below.

Table 10: Sampling Devices, Locations, and Frequencies for Continuous Monitoring at Above-Zone Monitoring Wells.

Parameter	Device(s)	Location	Min. Sampling Frequency (active / shut-in)	Min. Recording Frequency (active / shut-in)
Above-Zone Interval Pressure Monitoring	Bottomhole surface read-out pressure gauge	Downhole	5 sec. / 4 hours	5 mins. / 4 hours

Parameter	Device(s)	Location	Min. Sampling Frequency (active / shut-in)	Min. Recording Frequency (active / shut-in)
Casing Pressure Monitoring	Continuous annular pressure gauge	Surface	5 sec. / 4 hours	5 mins. / 4 hours
Tubing Pressure Monitoring	Continuous surface pressure gauge	Surface	5 sec. / 4 hours	5 mins. / 4 hours
Distributed Acoustic Sensing (DAS)	Fiber optic cable	Downhole	<1 sec. / <1 sec.	<5 min / <10 min
Distributed Temperature Sensing (DTS)	Fiber optic cable	Downhole	10 min / 10 min	10 min / 10 min

Notes:

- Sampling frequency refers to how often the monitoring device obtains data from the well for a particular parameter. For example, a recording device might sample a pressure transducer monitoring injection pressure once every two seconds and save this value in memory.
- Recording frequency refers to how often the sampled information is recorded to digital format (such as a computer hard drive). For example, the data from the injection pressure transducer might be recorded to a hard drive once every minute.

Above-ground pressure instruments shall be calibrated over the full operational range at least annually using ANSI or other industry recognized standards. Pressure transducers shall have a drift stability of less than 3 psi over the operational period of the instrument and an accuracy of ± 5 psi. Sampling rates will be at least once every 5 seconds.

Longleaf CCS, LLC will deploy fiber optic cable on the outside of the long string casing to the bottom of the well for all above-zone monitoring wells. Fiber optic cable will enable continuous micro-seismic and geophysical monitoring through DAS and well integrity assurance and leak detection through DTS.

F.4. Above-Zone Observation Well Mechanical Integrity Testing

Longleaf CCS, LLC will conduct the tests presented below in **Table 11** periodically during the injection phase to verify external mechanical integrity in all above-zone monitoring wells. Demonstrating and maintaining the mechanical integrity of above-zone monitoring wells is also meant to satisfy the State Oil and Gas Board of Alabama regulatory guidelines.

Table 11. Showing MIT Test Description and Frequency at Above-Zone Monitoring Wells.

Test Description	Frequency During Injection Phase
Annulus Pressure Test	Every 5yrs
Annulus Pressure Monitoring	Continuous
Pulsed Neutron Capture (PNC) Log	Baseline before injection; 3yrs after injection begins; Every 5yrs thereafter
Distributed Temperature Sensing (DTS)	Continuous
Temperature Logging	Baseline before injection; 3yrs after injection begins; Every 5yrs thereafter
Ultrasonic Cement Bond Inspection Log	Once before injection

PNC logs will be run at least once prior to the start of CO_2 injection, 3 years after injection begins, and every five years thereafter until the well is plugged and abandoned. Following a baseline, subsequent logs can be compared to determine changes in fluid flow adjacent to the wellbore and detect any CO_2 leakage above the confining zone. A temperature log will be deployed in conjunction with PNC logging to further evaluate mechanical integrity.

Continuous DTS monitoring will provide additional comprehensive mechanical integrity confirmation by continuously monitoring for areas along the wellbore with anomalous changes in temperature. The annulus between the tubing and the long string of casing will be filled with brine and a corrosion inhibitor and a pressure gauge will continuously monitor the annular pressure.

F.5. Above-Zone Plume and Pressure Front Tracking

Direct plume and pressure front tracking cannot occur in above-zone monitoring wells because they will be completed in a formation above the confining layer. However, Longleaf CCS, LLC will deploy CO_2 detection and pressure monitoring strategies in the above-zone monitoring wells in order to detect any CO_2 leakage.

Longleaf CCS, LLC will conduct cased hole PNC logs in the above-zone monitoring wells to indirectly detect any CO_2. PNC logs will be utilized once before injection, 3 years after injection begins, and every five years thereafter until the above-zone monitoring wells are plugged and abandoned. Additionally, Longleaf CCS, LLC will conduct VSP surveys to monitor the geophysical environment and potentially image any CO_2 leaks. These VSPs will occur once before injection, 3 years after injection begins, and every five years thereafter until the above-zone monitoring wells are plugged and abandoned or site closure.

A bottomhole pressure gauge with continuous surface read-out data and pressure gauges in the tubing and annulus at the surface will provide direct pressure monitoring data. Any anomalous changes in pressure could signal the presence of CO_2 above the confining zone.

F.6. Above-Zone Groundwater and Geochemistry Monitoring

In each above-zone monitoring well, fluid sampling will occur at least three times prior to injection, quarterly for the first year of injection, and annually through the injection and post-injection site care periods. **Table 12** below lists the parameters to be monitored and the analytical methods Longleaf CCS, LLC will use to analyze formation fluid. Sampling, laboratory, and handling methods are described in the *QASP*.

Table 12: Summary of Analytical and Field Parameters for Above-Zone Monitoring Well Fluid Samples.

Parameters	Analytical Methods
Above-Zone Monitoring Wells- Upper Tuscaloosa Formation	
Cations: Al, Ba, Mn, As, Cd, Cr, Cu, Pb, Sb, Se, and Tl	ICP-MS, EPA Method 6020B[5] or EPA Method 200.8[6]

[5] U.S. EPA. 2014. “Method 6020B (SW-846): Inductively Coupled Plasma-Mass Spectrometry.” Revision 2. Washington, DC.

[6] U.S. EPA. 1994. “Determination of Trace Elements in Waters and Wastes by Inductively Coupled Plasma – Mass Spectrometry.” Revision 5.4. Environmental Monitoring Systems Laboratory Office of Research and Development U.S. Environmental Protection Agency, Cincinnati, Ohio.

Parameters	Analytical Methods
Cations: Ca, Fe, K, Mg, Na, and Si	ICP-OES, EPA Method 6010D[7] or EPA Method 200.7[8]
Anions: Br, Cl, F, NO_3, and SO_4	Ion Chromatography, EPA Method 300.0[9]
Isotopes: S13C of DIC	Isotope ratio mass spectrometry
Dissolved CO_2 Total Dissolved Solids Water Density Alkalinity pH (field) Specific conductance (field) Temperature (field)	Coulometric titration, ASTM D513-16[10] Gravimetry, APHA 2540C[11] Oscillating body method APHA 2320B[12] EPA 150.1[13] APHA 2510[14] Thermocouple

G. Deep USDW Well Monitoring

Deep USDW monitoring wells will be completed in the lowest most USDW at the Longleaf CCS Hub, identified as the Chickasawhay Formation at an approximate depth of 1,700 ft SS. Four deep USDW monitoring wells will be completed to monitor the geochemistry of the Chickasawhay Formation fluid and detect any CO_2 leakage. **Figure 1** below displays the locations of these four deep USDW monitoring wells.

Longleaf CCS, LLC considered geologic site data, the presence of artificial penetrations, community impact, and the results of an extensive reservoir modeling effort to determine the location for deep USDW monitoring wells that will best ensure non-

[7] U.S. EPA. 2014. “Method 6010D (SW-846): Inductively Coupled Plasma-Optical Emission Spectrometry.” Revision 4. Washington, DC.

[8] U.S. EPA. 1994. “Determination of Trace Elements in Waters and Wastes by Inductively Coupled Plasma – Atomic Emission Spectrometry.” Revision 4.4. Environmental Monitoring Systems Laboratory Office of Research and Development U.S. Environmental Protection Agency, Cincinnati, Ohio.

[9] U.S. EPA. 1993. “Method 300.0: “Methods for the Determination of Inorganic Substances in Environmental Samples.” Revision 2.1. Washington, DC.

[10] ASTM Standard D513-16. 1988 (2016). “Standard Test Methods for Total and Dissolved Carbon Dioxide in Water,” ASTM International, West Conshohocken, PA. DOI: 10.1520/D0513-16, www.astm.org

[11] American Public Health Association (APHA), SM 2540 C, “Standard Methods for the Examination of Water and Wastewater”, APHA-AWWA-WPCF, 20th Edition (SDWA) and 21st Edition (CWA).

[12] Method 2320 B, Standard Methods for the Examination of Water and Wastewater, APHA-AWWA-WPCF, 21st Edition, 1997.

[13] U.S. EPA. 1971 (1982). “Method 150.1: pH in Water by Electromagnetic Method”, Cincinnati, OH.

[14] American Public Health Association (APHA), SM2510, 1992. Standard Methods for the Examination of Water and Wastewater”, APHA-AWWA-WPCF, 18th Edition, 1992.

endangerment to USDWs and local communities. The placement of the four deep USDW monitoring wells is based on an internal risk assessment and shown in **Figure 1**.

G.1. Placement of Deep USDW Wells

Deep USDW monitoring well UOB#3 will be placed in the middle of the four planned injection wells at the Longleaf CCS Hub where modeling has indicated that pressure will increase the greatest in the Paluxy injection interval during the injection period. Additional deep USDW monitoring wells UOB#1, UOB#2, and UOB#4 are placed in the far-field where the CO_2 plume is expected to migrate over time, near the edges of the AoR.

Existing well penetrations are not expected to be a risk for CO_2 leakage at the Longleaf CCS Hub because there are no existing wells within the AoR.

G.2. Deep USDW Well Monitoring Activities

In each deep USDW monitoring well, fluid sampling will occur at least three times prior to injection and occur annually through the injection and post-injection site care periods. **Table 13** below lists the parameters to be monitored and the analytical methods Longleaf CCS, LLC will use to analyze formation fluid. Sampling, laboratory, and handling methods are described in the *QASP*.

Table 13: Summary of Analytical and Field Parameters for Deep USDW Formation Fluid Samples.

Parameters	Analytical Methods
Deep USDW Monitoring Wells- Chickasawhay Formation	
Cations: Al, Ba, Mn, As, Cd, Cr, Cu, Pb, Sb, Se, and Tl	ICP-MS, EPA Method 6020B[15] or EPA Method 200.8[16]
Cations: Ca, Fe, K, Mg, Na, and Si	ICP-OES, EPA Method 6010D[17] or EPA Method 200.7[18]
Anions: Br, Cl, F, NO_3, and SO_4	Ion Chromatography, EPA Method 300.0[19]
Isotopes: S13C of DIC	Isotope ratio mass spectrometry
Dissolved CO_2 Total Dissolved Solids Water Density Alkalinity pH (field) Specific conductance (field) Temperature (field)	Coulometric titration, ASTM D513-16[20] Gravimetry, APHA 2540C[21] Oscillating body method APHA 2320B[22] EPA 150.1[23] APHA 2510[24] Thermocouple

[15] U.S. EPA. 2014. "Method 6020B (SW-846): Inductively Coupled Plasma-Mass Spectrometry." Revision 2. Washington, DC.

[16] U.S. EPA. 1994. "Determination of Trace Elements in Waters and Wastes by Inductively Coupled Plasma – Mass Spectrometry." Revision 5.4. Environmental Monitoring Systems Laboratory Office of Research and Development U.S. Environmental Protection Agency, Cincinnati, Ohio.

[17] U.S. EPA. 2014. "Method 6010D (SW-846): Inductively Coupled Plasma-Optical Emission Spectrometry." Revision 4. Washington, DC.

[18] U.S. EPA. 1994. "Determination of Trace Elements in Waters and Wastes by Inductively Coupled Plasma – Atomic Emission Spectrometry." Revision 4.4. Environmental Monitoring Systems Laboratory Office of Research and Development U.S. Environmental Protection Agency, Cincinnati, Ohio.

[19] U.S. EPA. 1993. "Method 300.0: "Methods for the Determination of Inorganic Substances in Environmental Samples." Revision 2.1. Washington, DC.

[20] ASTM Standard D513-16. 1988 (2016). "Standard Test Methods for Total and Dissolved Carbon Dioxide in Water," ASTM International, West Conshohocken, PA. DOI: 10.1520/D0513-16, www.astm.org

[21] American Public Health Association (APHA), SM 2540 C, "Standard Methods for the Examination of Water and Wastewater", APHA-AWWA-WPCF, 20th Edition (SDWA) and 21st Edition (CWA).

[22] Method 2320 B, Standard Methods for the Examination of Water and Wastewater, APHA-AWWA-WPCF, 21st Edition, 1997.

[23] U.S. EPA. 1971 (1982). "Method 150.1: pH in Water by Electromagnetic Method", Cincinnati, OH.

[24] American Public Health Association (APHA), SM2510, 1992. Standard Methods for the Examination of Water and Wastewater", APHA-AWWA-WPCF, 18th Edition, 1992.

H. Shallow USDW and Surface Monitoring

Shallow USDW monitoring wells at the Longleaf CCS Hub will be completed within a near-surface freshwater source to monitor the geochemistry of the formation fluid and detect any CO_2 leakage. Ten shallow USDW monitoring wells will be constructed, each on an existing well pad, as shown in **Figure 1**.

In each shallow USDW monitoring well, fluid sampling will occur at least three times prior to injection to establish a baseline and repeated annually through the injection and post-injection site care periods. **Table 14** below lists the parameters to be monitored and the analytical methods Longleaf CCS, LLC will use to analyze shallow groundwater. The sampling, laboratory, and handling methods are described in the *QASP*.

Table 14: Summary of Analytical and Field Parameters for Ground Water Samples.

Parameters	Analytical Methods
Shallow USDW Monitoring Wells (Near Surface)	
Cations: Al, Ba, Mn, As, Cd, Cr, Cu, Pb, Sb, Se, and Tl	ICP-MS, EPA Method 6020B[25] or EPA Method 200.8[26]
Cations: Ca, Fe, K, Mg, Na, and Si	ICP-OES, EPA Method 6010D[27] or EPA Method 200.7[28]
Anions: Br, Cl, F, NO_3, and SO_4	Ion Chromatography, EPA Method 300.0[29]

[25] U.S. EPA. 2014. "Method 6020B (SW-846): Inductively Coupled Plasma-Mass Spectrometry." Revision 2. Washington, DC.

[26] U.S. EPA. 1994. "Determination of Trace Elements in Waters and Wastes by Inductively Coupled Plasma – Mass Spectrometry." Revision 5.4. Environmental Monitoring Systems Laboratory Office of Research and Development U.S. Environmental Protection Agency, Cincinnati, Ohio.

[27] U.S. EPA. 2014. "Method 6010D (SW-846): Inductively Coupled Plasma-Optical Emission Spectrometry." Revision 4. Washington, DC.

[28] U.S. EPA. 1994. "Determination of Trace Elements in Waters and Wastes by Inductively Coupled Plasma – Atomic Emission Spectrometry." Revision 4.4. Environmental Monitoring Systems Laboratory Office of Research and Development U.S. Environmental Protection Agency, Cincinnati, Ohio.

[29] U.S. EPA. 1993. "Method 300.0: "Methods for the Determination of Inorganic Substances in Environmental Samples." Revision 2.1. Washington, DC.

Parameters	Analytical Methods
Dissolved CO_2	Coulometric titration, ASTM D513-16[30]
Total Dissolved Solids	Gravimetry, APHA 2540C[31]
Water Density	Oscillating body method
Alkalinity	APHA 2320B[32]
pH (field)	EPA 150.1[33]
Specific conductance (field)	APHA 2510[34]
Temperature (field)	Thermocouple

The need for surface monitoring, such as soil gas and atmospheric detectors, will be continually evaluated throughout the operational phase of the project. Given Longleaf CCS, LLC's current understanding of the subsurface environment and existing well penetrations, any endangerment to USDWs would likely be captured first by the deeper well monitoring protocols and activities set forth by this *Testing and Monitoring Plan*. As such, a network of soil-gas and atmospheric monitoring stations is not proposed at this time. Longleaf CCS, LLC will submit a separate EPA Monitoring, Reporting and Verification (MRV) Plan and comply with all monitoring and reporting requirements under Subpart RR of the Greenhouse Gas Reporting Program.

I. Seismicity and Fault Monitoring

As part of the geologic characterization of the Longleaf CCS Hub, six 2D seismic lines were acquired and interpreted from Seismic Exchange Inc. The objectives of the seismic analysis were as follows:

- To demonstrate the areal extent and continuity of the prospective CO_2 storage reservoir sands.
- To demonstrate the lateral continuity of the regional confining units.

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30 ASTM Standard D513-16. 1988 (2016). "Standard Test Methods for Total and Dissolved Carbon Dioxide in Water," ASTM International, West Conshohocken, PA. DOI: 10.1520/D0513-16, www.astm.org

31 American Public Health Association (APHA), SM 2540 C, "Standard Methods for the Examination of Water and Wastewater", APHA-AWWA-WPCF, 20th Edition (SDWA) and 21st Edition (CWA).

32 Method 2320 B, Standard Methods for the Examination of Water and Wastewater, APHA-AWWA-WPCF, 21st Edition, 1997.

33 U.S. EPA. 1971 (1982). "Method 150.1: pH in Water by Electromagnetic Method", Cincinnati, OH.

34 American Public Health Association (APHA), SM2510, 1992. Standard Methods for the Examination of Water and Wastewater", APHA-AWWA-WPCF, 18th Edition, 1992.

- To evaluate local structure and identify faults that may exist in the injection zone and confining units.

The seismic interpretation confirmed the continuity of both the Paluxy Formation, the targeted injection interval, and the Tuscaloosa Marine Shale, the regional confining unit. No faults or significant structural features that may disrupt the storage complex geology were found within the AoR.

East of the AoR and the Longleaf CCS Hub, there is the Hatter's Pond Fault that forms the eastern edge of the Mobile Graben (See section *B.3. Faults and Fractures* in the *Project Narrative*). The CO_2 plume is not expected to reach or interact with this inactive fault. Two in-zone monitoring wells have been placed on the east side of the Longleaf CCS Hub in order to monitor the location of the plume and pressure front in the area approaching the Mobile Graben. These wells will be equipped with pressure monitors and fiber optic cables to continuously monitor pressure and deploy DAS. The downhole pressure gauges will monitor for evidence of elevated pressure in the injection zone. DAS will monitor for any unusual micro-seismic events that may be warning signs for a loss of well integrity or locally induced seismicity.

J. Updating the Testing and Monitoring Plan

Pursuant to 40 CFR 146.90(j), this Plan will be reviewed at least once every five years after the start of injection until site closure. The Plan will be reviewed within one year of any plume and pressure front assessment or after any significant changes to the facility such as addition of injection wells. All reviews and updates will incorporate operational and monitoring data collected during the construction and injection periods.

Any amendments to this Plan made during the review process will be provided to the UIC Program Director for approval before their incorporation into the final update. If no amendments to the Plan are made during the review, a justification will be provided to the UIC Program Director.

K. Reporting

This section outlines the content and timing associated with report delivery to the UIC Program Director pursuant to the guidelines established in 40 CFR 146.91.

K.1. Semi-Annual Reporting

Per 40 CFR 146.91(a), Longleaf CCS, LLC will provide the UIC Program Director with semi-annual reports containing the following.

- Any changes to the physical/chemical characteristics of the CO_2 stream.
- The monthly averages, minimums and maximums recorded for the operating injection pressure, injection flow rate, injection volume or mass, and annular pressure.
- A description of any event where operating annulus or injection pressure limits were exceeded.
- A description of any shut down event triggered by injection well operating alarms and a description of the response taken.
- The monthly volume or mass of CO_2 injected over the current reporting period and cumulative volume or mass of CO_2 injected since the start of injection.

- The volume of annulus fluid added each month over the reporting period, if any.
- Any data collected or notable results from the implementation of the *Testing and Monitoring Plan*.

K.2. Reporting within 30 Days

Per 40 CFR 146.91(b), Longleaf CCS, LLC will provide the UIC Program Director with the following results from an injection well within 30 days of occurrence.

- The results of any MIT.
- The results of any well workover.
- The results of any other injection well test.

K.3. Reporting within 24 Hours

Per 40 CFR 146.91(c), Longleaf CCS, LLC will report the following events within 24 hours of occurrence.

- Any evidence that the injected CO_2 stream or associated pressure front may cause an endangerment to a USDW.
- Any noncompliance with a permit condition, or malfunction of the injection system, which may cause fluid migration into or between USDWs.
- Any triggering of a shut-off system downhole or at surface.
- Any failure to maintain mechanical integrity.

K.4. Advanced Notice of Activities and Document Retention

Per 40 CFR 146.91(d), Longleaf CCS, LLC will provide written notice to the UIC Program Director within 30 days in advance of the following activities at an injection well.

- Any planned well workover.
- Any planned stimulation activities other than stimulation for formation testing conducted under the initial collection of geologic information.

- Any other planned test of the injection well by Longleaf CCS, LLC.

Per 40 CFR 146.91(f), Longleaf CCS, LLC will retain records in the following manner.

- All site characterization data will be retained throughout the life of the geologic sequestration project and for at least 10 years following site closure.
- Data on the nature and composition of all injected fluids will be retained for at least 10 years after site closure.
- Any monitoring data collected through the *Testing and Monitoring Plan* will be retained for at least 10 years after it is collected.
- Well plugging reports and all post-injection site care data will be retained for at least 10 years after site closure.